ORIGINAL

0000144612

BEFORE THE ARIZONA CORPORATION C...

COMMISSIONERS
BOB STUMP - Chairman
GARY PIERCE
BRENDA BURNS
BOB BURNS
SUSAN BITTER SMITH

IN THE MATTER OF THE APPLICATION OF ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN.	DOCKET NO. E-01773A-12-0305 **STAFF'S NOTICE OF FILING DIRECT TESTIMONY**

The Utilities Division ("Staff") of the Arizona Corporation Commission ("Commission") hereby submits the Direct Testimony, excluding rate design issues, of Staff witnesses Randall Vickroy, John Antonuk, Dennis M. Kalbarczyk and Richard Mazzini (Public) in the above-referenced matter.

A confidential version of John Antonuk and Dennis M. Kalbarczyk's Direct Testimony will be provided under seal to the Commissioners, their Assistants, the assigned Administrative Law Judge, and the parties that have signed the Protective Agreement in this case.

RESPECTFULLY SUBMITTED this 1st day of May, 2013.

Arizona Corporation Commission
DOCKETED
MAY 1 2013
DOCKETED BY TJM

Bridget A. Humphrey, Staff Attorney
Scott M. Hesla, Staff Attorney
Legal Division
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007
(602) 542-3402

2013 MAY 1 PM 3 10
AZ CORP COMMISSION
DOCKET CONTROL
RECEIVED

Original and thirteen (13) copies of the foregoing were filed this 1st day of May, 2013 with:

Docket Control
Arizona Corporation Commission
1200 West Washington Street
Phoenix, Arizona 85007

Copy of the foregoing mailed/and or emailed
this 1st day of May, 2013 to:

Michael M. Grant
Jennifer Cranston
GALLAGHER & KENNEDY, P.A.
2575 E. Camelback Road
Phoenix, AZ 85016-9225
Attorneys for AEPCO

Michael W. Patten
ROSHKA, DEWULF & PATTEN, PLC
400 E. Van Buren, Suite 800
Phoenix, AZ 85004
Attorneys for Trico

Russell E. Jones
WATERFALL ECONOMIDIS CALDWELL
HANSHAW & VILLAMANA, P.C.
5210 E. Williams Circle, Suite 800
Tucson, AZ 85711
Attorneys for Trico

Vincent Nitido
Karen Cathers
TRICO ELECTRIC COOPERATIVE, INC.
8600 W. Tangerine Road
P.O. Box 930
Marana, AZ 85653

Jeffrey W. Crockett
BROWNSTEIN HYATT FARBER
SCHRECK, LLP
One E. Washington St., Suite 2400
Phoenix, AZ 85004
Attorneys for SSVEC

Kirby Chapman
SSVEC
322 E. Wilcox Drive
Sierra Vista, AZ 85635

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01773A-12-0305

DIRECT

TESTIMONY

(COST OF CAPITAL)

OF

RANDALL VICKROY

(CONSULTANT)

ON BEHALF OF THE STAFF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MAY 1, 2013

TABLE OF CONTENTS

EXHIBITS

Introduction

Introduction and Qualifications

Q. Please state your name, position and business address.

A. My name is Randall Vickroy. I am a senior consultant for The Liberty Consulting Group ("Liberty"). My Liberty business address is: The Liberty Consulting Group, 65 Main Street, P.O. Box 1237, Quentin, Pennsylvania 17083.

Q. Have you prepared summaries of your background and qualifications?

A. Yes, they are provided in Exhibit REV-1.

Q. Mr. Vickroy, please describe your educational background and professional experience as they relate to the subjects of this testimony.

A. I spent 12 years with a major Mountain States electric and gas utility, starting as a financial analyst in the corporate finance and planning department, and then became financial supervisor, director of analysis, business development manager, and assistant to the chief financial officer. My responsibilities included financial planning, capital acquisition, capital spending analysis and allocation, treasury operations, securitization financing, project financing, mergers and acquisitions, cash management, and investor relations.

I have been consulting since 1991 on corporate finance and business issues in the electricity, natural gas, and telecommunications industries. During this time, I have provided consulting services to utility commissions and to companies in over 30 states and in three foreign countries. I received a Bachelor of Arts from Monmouth College with a major in business administration and a Masters of Business Administration degree from the University of Denver with an emphasis in finance.

Q. For whom are you appearing in this proceeding?

A. I am appearing on behalf of the Arizona Corporation Commission ("ACC") Utilities Division ("Staff").

Q. What is the purpose of your testimony?

A. My testimony provides a review, evaluation, and recommendations addressing cost of capital issues for the Arizona Electric Power Cooperative, Inc. ("AEPCO" or the "Cooperative") rate filing, as summarized in the Cooperative's Schedules A-1 and A-2 for the test year ended December 31, 2011, as adjusted. Cost of capital issues include the cost of debt, business risk factors as they affect the cost of capital, financial coverage ratios such as Times Interest Earned Ratio ("TIER") and Debt Service Coverage ("DSC"), equity ratios, and rating agency cash flow metrics and indicators. I will also discuss my evaluation of whether AEPCO's cost of capital request provides adequate margins and debt coverage in light of business risks facing the Cooperative.

Q. Why has AEPCO requested a rate decrease in this filing?

A. AEPCO has stated in its testimony that the Rural Utilities Service ("RUS") requires it periodically to update its depreciation rates, and that ACC rules require a rate case before implementing any changes. AEPCO hired Black and Veatch to perform a depreciation study, which AEPCO presented, along with the testimony of Mr. Peter Scott. The depreciation study recommends an increase in depreciation rates, which the Cooperative offers as a primary reason for this rate case. AEPCO also requests a 2.92 percent rate decrease to reflect an anticipated net decrease in operating expenses that the Cooperative has projected in its adjustments to the test period.

AEPCO's financial results decreased markedly in 2011. Net margin decreased from \$9.50 million in 2010 to \$1.86 million. AEPCO expects, however, that several changes will substantially affect its financial outlook in 2012 and beyond. The Cooperative has therefore adjusted its 2011 actual results for items it believes reflect ongoing conditions. The largest items in recognition of which AEPCO has adjusted the 2011 test year consist of: (a) decreases in coal prices and coal transportation costs of almost $11 million, and (b) lower staffing costs of $2.3 million resulting from a 2011 reduction in personnel. New point-to-point transmission contracts with SWTC offset these cost decreases, producing additional costs of $6.2 million. Higher depreciation resulting from rates from the depreciation study would also serve to increase depreciation expense by $2.5 million annually. These changes and several smaller adjustments presented by AEPCO in the filing would produce the net expected impact of lowering expenses and increasing net margins by $4.6 million annually as compared to 2011. AEPCO's Schedule C-1 shows these changes. AEPCO has proposed a revenue decrease of $4.5 million, in order to offset the anticipated lower expense levels. The Cooperative projects about $1.95 million in annual net margins as a result.

<u>AEPCO Financial Results</u>

Q. How have APECO's financial results and financial health metrics changed over the past five years?

A. Exhibit REV-2 shows AEPCO's realized DSC ratios in the 1.3 to 1.7 times range in each year from 2008 through 2010. These ratios comfortably exceed its mortgage document requirements. AEPCO's 2010 DSC of 1.66 in 2010 declined to only 1.19 times in 2011 with new, revised rates in effect. TIER levels exceeded two times for 2008, ran at 1.94 times for 2009, and dropped moderately to 1.88 times for 2010. TIER levels then decreased significantly in 2011 - to only 1.18 times.

AEPCO's equity ratio has increased from a very low level of 5 percent at the end of 2005 to a robust 31.43 percent at the end of 2010, falling to 29.49 percent at December 31, 2011.

AEPCO's financial results and DSC and TIER covenant coverage ratios have deteriorated significantly in 2011, as compared to all other years since 2007.

Q. What do AEPCO's actual financial results in 2011 as filed, and its unaudited results for 2012 show?

A. AEPCO's Schedule A-2 reports actual net margins of about $1.86 million for the test year ended December 31, 2011. The DSC for 2011 was 1.19 times and the TIER was 1.18 times, as shown in Schedule A-2 to Mr. Gary Pierson's testimony.

AEPCO's filing projected that its adjustments for decreased coal costs, increased transmission expense, and other adjustments to operating expenses described previously would increase net margin to $6.5 million, DSC to 1.56 times, and the TIER to 1.70 times. AEPCO forecasts that its rate decrease would reduce net margin to $1.96 million.

AEPCO has recently provided its unaudited financial results for 2012. We believe them appropriate to consider in examining the rate request. AEPCO reports preliminary unaudited net margins of about $5.1 million for the year ended December 31, 2012. The DSC for 2012 based on preliminary results was 1.31 times and the TIER was 1.56 times. Please see Exhibit REV-2.

Q. Please explain the relevance of AEPCO's actual financial results in 2011 and 2012.

A. 2011 was the first year new rates took effect following AEPCO's last rate case. Rates were set based on a target DSC of 1.32 times. However, AEPCO only realized a net margin of $1.86 million and a DSC of 1.19 times under its new rate levels. The experienced "attrition" in realized returns is a relevant consideration in evaluating the business risk of AEPCO, when new rates become effective. AEPCO experienced better results in 2012, because it realized lower coal expenses and staff reduction benefits. These benefits were not in 2012 yet offset by AEPCO's proposed increased depreciation expense and proposed increased transmission charges from Southwest Transmission Cooperative, Inc. ("SWTC").

Q. Please explain the relevance of AEPCO's financial health ratios and metrics.

A. The DSC, TIER, and equity as a percent of total capitalization comprise primary financial ratios and indicators of AEPCO's financial health under RUS loan documents. The Cooperative's RUS mortgage agreement debt covenants and other loan and credit agreements require both a DSC and a TIER of at least 1.0 times in two of three consecutive years. Exhibit REV-2 provides the Company's DSC, TIER, and equity ratio for each year from 2008 through 2012 (2012 is unaudited), as reported in the RUS Form 12.

We consider the DSC and credit rating cash flow ratios more important than the TIER. Generation & Transportation ("G&T") cooperatives such as AEPCO most often use the DSC to set margin levels. The DSC takes into account cash flow items (such as depreciation and principal payments), and provides a better indicator of a cooperative generation enterprise's production of sufficient cash to meet its interest and principal requirements.

Q. What results has AEPCO experienced with respect to ratios relevant to credit ratings?

A. Exhibit REV-2 provides AEPCO's credit cash flow metrics for 2008 through 2012. The ratio of funds from operations to interest on long-term debt ("FFO/Interest") for the three-year period from 2010 and 2012 averaged 2.34 times. This result placed AEPCO in the middle of Moody's Investors Service ("Moody's") range for "A" rated G&Ts. Funds from operations to total debt ratio FFO/Debt for the most recent three-year period averaged 6.48 percent. This result placed AEPCO at the lower end of the range for "A" level rating criteria. These cash flow metrics offer important measures of the recent, historical cash flow adequacy used by the credit rating agencies.

Q. How has AEPCO calculated its proposed rate decrease of 2.92 percent with respect to financial ratios?

A. AEPCO based its requested rate change upon a targeted DSC of 1.32 times for the test year, after considering its proposed adjustments. This target DSC uses the coverage level allowed by the preceding rate Order in 2010. The requested rate decrease would result in a corresponding TIER of 1.21 times, and produce calculated net margins of about $1.96 million annually. See Schedule A-2 to the testimony of Gary Pierson. AEPCO has also estimated that the reduction in rates would increase equity from 30.3 percent at December 31, 2011, to 32.4 as a percentage of capitalization. AEPCO would retain the $2 million margin in its equity capital, and reduce its long-term debt by $16.6 million in 2012.

<u>AEPCO Cost of Debt</u>

Q. Please summarize AEPCO's calculations of its cost of debt.

A. AEPCO's Schedules D-1 and D-2 calculate long-term debt and interest for the end of the test year at December 31, 2011, and for the end of the projected year at December 31, 2012. AEPCO includes: (a) $216.7 million of long-term debt having an average rate of 4.87 percent, and (b) $3.7 million of short-term debt at 3.77 percent for the test year of 2011. Schedule D-1's cost of debt summary for AEPCO produces a composite rate of 4.79 percent on $220.5 million of total debt outstanding.

Q. Does AEPCO expect its long-term debt to change significantly following the 2011 test period?

A. Yes. AEPCO projects that in 2012 long-term debt will be reduced to $200.1 million, and have an average rate of 4.62 percent. AEPCO expects a net reduction in long-term debt of about $16.6 million. The biggest change in long-term debt between the two years would come from a 2012 payoff of $15.1 million of 7.74 percent Central Bank for Cooperatives debt. AEPCO projects annual interest on long-term debt to decrease from $10,546,622 for the test period ended December 31, 2011, to $9,238,437 for 2012. The reduction in the long-term debt interest results from having $16.6 million less of long-term debt outstanding, and from reducing long-term debt's average rate from 4.87 percent to 4.62 percent. Removal of the higher-cost debt with Central Bank for Cooperatives is the primary source of this change.

AEPCO expects its long-term debt at the end of 2012 to consist primarily of Federal Financing Bank ("FFB") debt, which would account for about $157.2 million (over 78 percent) of long-term debt outstanding. AEPCO also estimates that it will have long-term debt of $30.0 million outstanding at December 31, 2012, with the National Rural Utilities Cooperative Finance Corporation ("CFC"). AEPCO also anticipates CFC Series 1994A bonds totaling $12.8 million.

Q. Has AEPCO requested the inclusion of short-term debt in the capital structure?

A. Yes. AEPCO had at the end of the test year on December 31, 2011, $3.7 million outstanding on its $25 million credit facility with CFC. AEPCO included this short-term debt amount in its cost of debt calculation. This debt has an interest rate of 3.77 percent. AEPCO's underlying rationale in including short-term interest in the cost of capital is that a similar level of short-term debt will be required to fund the various working capital needs in 2012. This rationale is reasonable for the cost of debt calculation, and its inclusion results in a lower composite cost of debt.

Q. What is your evaluation of AEPCO's requested cost of debt as presented in Schedules D-1 and D-2?

A. Year-end 2012 information is now available. AEPCO should therefore use updated cost of long-term and short-term debt information (as of December 31, 2012) to calculate the cost of debt. The Cooperative's projections should cause the cost of debt to fall by approximately 25 basis points, were it to use the latest information available.

AEPCO Return Requirements

Q. Please explain your method for estimating AEPCO's cost of capital and coverage requirements.

A. I have evaluated AEPCO's cost of capital and coverage requirements based on risk evaluation techniques used by the credit rating agencies, and I have considered AEPCO's specific business situation as well. The rating agency techniques include both quantitative criteria based on financial metrics and qualitative criteria associated with the business risks of G&T cooperatives. The financial credit metrics provide a quantitative foundation for the financial results required to achieve a solid investment grade rating. I then factored in qualitative criteria also used by the rating agencies to evaluate the business risks specific to AEPCO.

Using both the quantitative and qualitative risk factors, I then evaluated the request for rate levels based on a target DSC coverage ratio. The DSC ratio is preferred for use in evaluating G&Ts' financial strength, because it takes into consideration cash requirements and principal payments, which are substantial for most cooperatives. I considered AEPCO's prospects as evaluated by the business risk criteria to determine whether the target return and coverage levels requested are reasonable and adequate.

Q. How do you define the required rate of return or cost of capital used to set rates for AEPCO?

A. The determination of a coverage ratio to calculate AEPCO's return requirements should produce financial results that will allow the Company to meet member power requirements, maintain financial strength, and raise capital from RUS, CFC, and capital markets, as necessary. A fundamental principle of utility finance, whether the utility is investor-owned or a cooperative, holds that an enterprise must be able to attract capital at a reasonable cost in order to build and maintain its physical plant and to meet its public service obligations. The failure to maintain the financial integrity of a cooperative is not in the interests of either its members, as owners, or lenders. At a minimum, an entity like AEPCO must be afforded the opportunity not only of assuring its financial integrity to attract additional capital as needed, but also of achieving margins and financial results commensurate with its risk profile.

Q. Please explain your basis for determining the appropriate risk parameters for AEPCO.

A. The three major credit rating agencies: Moody's Investors Service ("Moody's"), Standard and Poor's ("S&P"), and Fitch comprise the established sources of evaluations of risk and credit standing. The rating agencies have similar criteria for evaluating the risks of G&T cooperatives. Moody's has refined its criteria for rating G&Ts, and has clearly defined its actual ratings and reasoning for electric G&T cooperatives. Most of the cooperatives rated by Moody's are among the larger U.S. G&Ts. Moody's also rates a few medium and smaller-sized ones.

AEPCO has not established a credit rating. However, I do use rating criteria that Moody's and the other rating agencies have specifically designed for G&Ts, regardless of size. These rating agency criteria are appropriate for determining a reasonable expectation for financial metrics and results, provided that one adequately considers the specific business and financial risks of AEPCO.

Q. What primary factors do rating agencies consider important in assessing the risk of G&T cooperatives?

A. The rating agencies' analysis of U.S. electric G&T cooperatives focuses on five key rating factors. These factors encompass 14 elements or sub-factors considered central to assigning ratings in this sector. These rating factors include quantitative and qualitative measures for establishing the risk profile of a G&T cooperative. The five key factors and the Moody's weighting of each factor follow:

1. Financial Performance and Metrics (40 percent)
2. Long-term Wholesale Power Supply Contracts/Regulatory Status (20 percent)
3. Rate Flexibility/Rate Shock Exposure (20 percent)
4. Member/Owner Profile (10 percent)
5. Size (10 percent).

Financial performance and strength provide indicators of a G&T cooperative's ability to meet its obligations, especially interest and debt service. The rating agencies analyze financial indicators and ratios over the most recent three-year period to measure the ability to cover fixed and variable obligations. They analyze the DSC and the TIER, recognizing that these two ratios have been used to measure minimum compliance with RUS loan documentation for many years, and provide a bare, minimum level of financial results that must be met. They also analyze cash flow indicator ratios. Specifically, funds from operations coverage of interest ("FFO/Interest") and funds from operations coverage of debt ("FFO/Debt"). These ratios are most important to the rating agencies, because they provide insight into the amount and quality of a cooperative's cash flow and its ability to service its debt. The rating agencies also evaluate cooperative equity as a percentage of total capitalization, to determine how much flexibility exists on the balance sheet to absorb unexpected events and losses. These five financial ratios comprise the primary quantitative determinants of the risk profile for G&T cooperatives. Together, these ratios account for 40 percent of the weighting in rating agency evaluations. Moody's notes that it may score companies higher or lower than its historical results if they expect future, significant changes in financial performance. Exhibit REV-3 includes ranges that correspond to an "A" credit rating for each of the five metrics. An "A" rating comprises the average for rated G&T cooperatives that use their ratings to access capital markets.

Q. What qualitative credit rating criteria make up the remaining 60 percent of the risk evaluation?

A. The remaining four criteria categories used to develop risk profiles account for 60 percent of the evaluation, and they exhibit a more qualitative nature. One should recognize that long-term wholesale power supply contracts between G&T cooperatives and their members can provide the G&Ts with a high degree of assurance that costs and capital investment can be recovered in rates charged to the members. Most of these wholesale contracts require the member cooperatives to purchase all or virtually all of their power supply from the G&T. The members must also pay their pro-rata portion of the G&T's

fixed and variable costs. A higher percentage of capacity and energy sold to members is considered less risky than outside wholesale contracts or other sales to non-members. Regulatory status also comprises part of this ratings factor. Arizona is one of 10 states that has regulatory jurisdiction over cooperative rates. Regulatory control over the rate setting process is considered by the rating agencies to give a cooperative less discretion to raise or lower rates if needed.

Rate flexibility and rate shock exposure forms another credit factor related to competitiveness and cost recovery efficiency.

New-build exposure is a primary consideration that rating agencies measure. It is becoming increasingly important in assessing G&T business risk. A larger construction program is considered to pose negative credit risk. The issuance of increased debt to finance the program increases risk. Cost competitiveness comprises another factor gaining more emphasis recently. Cost competitive cooperatives are viewed more favorably, because they have greater flexibility to raise rates and absorb rate shock as costs rise or to build equity capital to levels that would cover operational problems.

The timing and extent to which a G&T cooperative can increase rates is influenced by how active its Board of Directors has historically been regarding rate actions. Fuel and purchased-power adjustment mechanisms are viewed favorably, especially under shorter recovery deferral lengths. The degree of reliance on purchased power comprises another credit factor. Heavy reliance on purchases indicates higher exposure to price volatility.

Member profiles measure the degree of a G&T's residential sales (considered less risky) by its member systems. The consolidated member's equity capital as a percentage of capitalization is also considered in determining the strength of members.

A size factor applies also, measured by megawatt-hour sales and by net property, plant, and equipment. The rating agencies believe that megawatt-hour sales comprise important indicators of economies of scale. They also believe that possessing a greater asset base may be beneficial if the G&T can benefit from having a larger pool of assets and a more diverse source of fuels to operate the generation assets that it owns. Lower asset concentration in generating plants is considered preferable due to the risk of extended outages and replacement power costs.

Q. Please explain how you analyzed the rating agency targets for financial metrics to apply to AEPCO.

A. I used Moody's financial metrics for electric G&T cooperatives to determine the financial criteria for an "A" credit rating. An "A" credit rating would allow access to capital markets other than the RUS, which likely will be needed by AEPCO in the future. AEPCO's small size and the fact that it has not accessed capital markets to date would require a strong credit profile to be able to access these markets, as the Cooperative recognizes. Moody's has published for each rating level a range for each of the five key financial metrics for G&Ts discussed earlier. Exhibit REV-3 provides the ranges of financial metrics that qualify for the "A" rating level, as documented by Moody's.

Please note that the exhibit's values for the mid-points of the "A" rating category for the financial metrics generally lie close to the pro forma results of AEPCO's rate request target. AEPCO's 3-year averages for the financial ratios from 2010-2012 also compare favorably. The rating mid-point for DSC coverage, for instance, falls at 1.30 times. AEPCO has requested a coverage of 1.32 times. Based solely upon historical, quantitative metrics, AEPCO has produced financial results that could qualify it for an investment-grade credit rating. The financial metric qualifications in total comprise 40 percent of the evaluation.

We must hesitate, however, because where AEPCO lies with regard to several qualitative factors and in light of its business risks accounts for 60 percent of the evaluation; *i.e.*, these factors carry more weight than the history-based ratios.

Q. How do the quantitative factors influence the analysis of AEPCO's risk profile?

A. The financial metrics provide a quantitative basis for determining AEPCO's risk profile. We have determined that the financial targets included in its rate request, if they were to be realized over a period of years, would probably qualify AEPCO for an investment-grade credit rating and the ability to access capital markets. Moody's gives a 40 percent weight to the financial metrics and 60 percent to the remaining four rating factors. I should note here that non-financial metrics, or qualitative, ratings factors to be discussed often tend to have an overriding influence on whether an enterprise can actually realize the targeted returns and ratios included in rate filings, and on overall business risk. This is especially true in the case of AEPCO.

Q. What is your evaluation of AEPCO with regard to member contracts and regulatory status?

A. AEPCO has higher risk with regard to the qualitative considerations concerning long-term wholesale power supply contracts and regulatory status. The Company currently has all 555 MW of capacity at its Apache station committed to members under long-term requirements contracts through 2035. That commitment would generally be considered a strongly positive factor. However, AEPCO sells almost 90 percent of its capacity and energy to three partial requirements members. These partial requirements members individually plan for and acquire incremental resources above their contractual commitments regarding capacity and costs associated with AEPCO's generating assets. The partial requirements customers also control the acquisition of their energy needs on a daily basis, and also are not currently in AEPCO's system control area. The partial requirements members' contractual rights, past actions to plan for their own incremental electric resources, and their dispatch scheduling for their energy needs above minimum requirements adds for AEPCO substantial business risk above that typical of G&Ts with all-requirements contracts.

AEPCO is also rate-regulated by the ACC, which Moody's considers a negative factor for purposes of business risk and credit ratings. The combination of AEPCO's partial requirements member wholesale contract status and regulatory status would place AEPCO below investment grade levels for these categories, which is a significant negative ratings factor.

Q. Please explain the rate flexibility/rate shock qualitative factors as they relate to AEPCO.

A. The rate flexibility/rate shock factors also indicate higher levels of risk for AEPCO. Two of the rate-flexibility categories would place AEPCO in Moody's "Ba" category or lower; *i.e.*, in a high-risk category. These two factors consist of the new construction build exposure and rate competitiveness categories. These factors bring high levels of risk for AEPCO, and must be considered as important to not only the Cooperative's business risk measures, but also to future prospects of the entity as an economic source of capacity and energy to its member/owners.

The EPA's recent ruling regarding environmental compliance requirements for AEPCO's two coal-fired units at the Apache station have greatly increased the risk of new-build exposure relative to the existing asset base. This factor is crucial because G&T cooperatives largely finance new capital investment with debt and rely upon rate increases to service the debt. AEPCO faces the prospect of at least $190 million of capital expenditures to meet EPA requirements over the next 3 to 5 years. This would almost double the Company's fixed assets and rate base, and impose the need for a substantial increase in rates. AEPCO estimates the amount of that increase to be 18 percent or more, considering the new EPA expenditures alone. The "construction build" exposure that AEPCO faces is major, presenting a business risk factor that we view as in the "high risk" category.

The consideration of rate competitiveness and the potential for rate shock exposure also fall in the high risk category for AEPCO. The Company's rates, as compared with other regional utilities, are currently high. Its member rates significantly exceed those of Tucson Electric Power Company, Arizona Public Service Company and Salt River

Project for both the residential and large power categories. Board of Director presentations in 2010, 2011 and 2012 observe this factor. Assessing the potential for rate shock exposure is important for AEPCO. AEPCO's rate shock exposure is very high because the EPA compliance requirements greatly increase this risk.

The Cooperative's low percentage of purchased power as compared to total supply addresses another factor of importance in determining credit risk. AEPCO's comparatively low reliance on purchased power comprises a positive ratings factor currently. However, the diminishing competitiveness of Apache may increase purchases. Lower natural gas pricing has caused regional electric prices to drop significantly in the recent past; this trend is expected to continue.

Q. What is your evaluation of the other qualitative business risk factors?

A. The rating agencies also consider the risk of member cooperatives; G&Ts have close and encompassing ties to their members through purchase contracts. The member/owner profile risk factors include system residential sales as a percentage of the total. The AEPCO members have a residential sales factor below average for G&Ts nationally, according to RUS Key Performance Indicator comparisons. This factor taken alone would seem to be negative for AEPCO. A moderating factor arises from the comparatively small percentage of industrial revenue (considered more risky) among AEPCO's members. This risk factor therefore becomes neutral for AEPCO. The equity capitalization of AEPCO's members comprises another risk measure. The below-average (again measured by RUS performance indicators nationally) equity percentages of AEPCO's members produce a negative influence.

Size also weighs against AEPCO, for both megawatt-hour sales and net property plant and equipment. AEPCO is only a fraction of the size of most G&T companies by these measures.

Q. What is your overall evaluation of the non-financial business risk and rating factors?

A. The non-financial rating factors combine to give AEPCO very high levels of risk. This is true for many of the metrics to which Moody's assigns the majority of the weighting (60 percent) in evaluating overall G&T risk. The construction build risk is quite high. AEPCO faces over $190 million in estimated EPA compliance capital expenditures, which would almost double its rate base. AEPCO's rate competitiveness risk is also high. The Company's rates are already high by regional standards, and its coal-fired generating units have become less competitive versus the market due to lower natural gas prices.

The partial requirements status of almost 90 percent of member requirements has caused operational issues and general member unrest. These factors cause substantial risk compared to G&Ts relying on all-requirements contracts. AEPCO's purchased power as a percentage of supply resources is low currently, but could increase. Member residential sales percentages and member equity capitalization produce moderately negative factors. The Cooperative's small size by megawatt-hour sales and asset base and its concentration of assets at the Apache site also create negative business risk factors. Overall, the qualitative business risk factors place AEPCO in a high risk category.

Q. Does Moody's include other factors of consequence for AEPCO?

A. Yes. Moody's includes an appendix to its G&T rating guidelines. These "Key Rating Issues Over the Intermediate Term" are specific to the types of events and future challenges that can have a strong effect on the business risk of a G&T cooperative. Moody's emphasizes three key issues: global climate change and environmental awareness, large capital expenditures and rising costs for new generation and transmission, and larger rate increases that may test members' willingness to raise rates.

The first issue relates to the greatly increasing environmental expenditure estimates among G&Ts with significant coal-fired generation. Such expenditures are likely to continue to increase with the imposition of new and sometimes uncertain requirements with respect to carbon emissions. This issue applies directly and strongly to AEPCO and the environmental expenditures that it faces in the future, which constitute a crucial and highly negative business risk factor.

The second key issue of large capital expenditures and rising costs is also highly relevant to AEPCO. Potential construction programs such as those that face the Cooperative will be challenging to execute on a timely and cost-effective basis.

The third issue, larger rate increases that may test members' willingness to raise rates, is also highly applicable to AEPCO. High levels of capital expenditures such as those faced by the Cooperative would put substantial upward pressure on AEPCO's already high rate levels. The Cooperative has recognized in public statements regarding the EPA environmental requirements the negative impact that such requirements would have on end users.

We have already considered these three issues in our evaluation of qualitative business risks (discussed above). However, the emphasis placed on these issues as "overriding evaluative factors" gives them additional focus in evaluating AEPCO's business status.

Q. Do you believe that AEPCO has substantially greater business risk than at the time of its last rate case in 2010?

A. Yes. The vast challenge of the EPA requirements and the capital expenditures that they entail has arisen within the past year. This crucial challenge and risk factor was not considered in the Cooperative's 2010 rate case.

AEPCO's generation has also become less competitive in the last few years. The Company has negotiated decreases in its coal contracts and rail transportation rates, but those positive developments have been offset by steeply declining natural gas prices, which have contributed to a fundamental change in the relationship of coal and gas-fired energy prices. The large amount of efficient combined cycle gas-fired capacity in the region has made this resource extremely competitive with some base load coal plants. This change has had a significant impact on the operations of the Apache coal units, which are now being used less frequently. The long-term economic viability of some coal-fired units has become uncertain over the past few years as a result, a crucial consideration that AEPCO must deal with in the future.

<u>Rate Sufficiency</u>

Q. Do you believe that AEPCO's requested target DSC ratio of 1.32 will provide sufficient returns in the environment that you have described?

A. No. AEPCO is requesting the same target DSC ratio of 1.32 as approved in the previous rate case Decision. AEPCO's business situation and challenges have changed substantially. A DSC of 1.32 would require a rate decrease. Staff does not support a rate decrease.

Q. Please explain why Staff does not support a rate decrease.

A. Staff believes that a rate decrease would not result in sufficient margins or coverage ratios. The request for a rate decrease is questionable for several reasons:

1. The Cooperative faces much greater business risk due to EPA environmental mitigation requirements that could almost double its rate base.

2. AEPCO has high costs and rate levels that could increase significantly with its high "construction build" situation.

3. Its key generation resources have become less competitive with market generation sources and now have uncertain long-term economic viability.

Q. Does Staff recommend a rate decrease at this time?

A. No. We have explained above that AEPCO faces extremely challenging business and economic risks. The nature and level of these risks make even the higher end of a normal DSC range (1.20 to 1.50) insufficient. The high-risk situation that AEPCO faces justifies the consideration of DSC ratios well above 1.50. Yet, it would only take a DSC of 1.56

(only marginally out of this normal range) to eliminate AEPCO's proposed rate decrease of $4.5 million entirely. Under the circumstances, leaving rates at present levels is a prudent course.

Q. Please summarize your reasons for recommending that AEPCO not decrease its rates at this time.

A. AEPCO faces great challenges and an uncertain business environment, which threatens its long-term economic viability and ability to provide competitively-priced electric supply resources to its members. AEPCO should not consider reducing its rates until the crucial challenges that face the Cooperative, especially the EPA requirements and the long-term economic viability of the Cooperative's generation resources, are fully evaluated and the future path charted. The huge uncertainties and risks that face the Cooperative on a going-forward basis should preclude a rate decrease for AEPCO at this time.

In addition, a rate decrease at this may cause a substantial increase in rates in the future, in order to take care of the challenges discussed above. A large increase in rates in the future would be contrary to the concept of gradualism.

Q. Does this conclude your direct testimony?

A. Yes, it does

Randall E. Vickroy

Areas of Specialization

Mr. Vickroy has over 30 years of experience in the utility industry, including 20 years as a management consultant. He has managed and performed numerous high-level consulting assignments at companies and utility commissions in over 35 states. His areas of expertise include corporate finance and treasury, investment and liability management; capital markets and financing vehicles; utility industry restructuring; utility rates and pricing; holding company lines of business and utility insulation; strategy and planning issues; asset valuations and decision-making; energy supply procurement; energy supply economics; commodity risk management; capital and expense budgeting and forecasting; corporate resource allocation; and financial and economic analysis.

Relevant Experience

Management and Operations Audits

Lead Consultant on financial management, strategic planning, capital and expense budgeting, electrical energy and capacity purchases and hedging on Liberty's management and operations audit of the electricity and natural gas businesses of Interstate Power and Light and Alliant Energy for the Iowa Utilities Board.

Lead Consultant on financial management, planning, capital and expense budgeting, electrical energy and capacity purchases and hedging on Liberty's management and operations audit of the electricity and natural gas businesses of Iberdrola SA/Iberdrola USA/NYSEG and RG&E for the New York Public Service Commission.

Lead Consultant on electrical energy and capacity purchases and sales, hedging policies and operations, and capital budgeting on Liberty's management and operations audit of the electricity, natural gas, and steam operations of Consolidated Edison for the New York Public Service Commission.

Lead Consultant for Liberty's audit of East Kentucky Power Cooperative, which included examinations of governance, planning, finance and budgeting. Liberty performed for the Kentucky Public Service Commission an examination of governance at the generation and transmission cooperative serving 16 distribution cooperatives across the state. This study came in the wake of significant financial difficulties and also assessed planning, budgeting, financial, and risk functions and activities.

Lead Consultant in Liberty's comprehensive analysis of the ratemaking implications of Commonwealth Edison's Chicago electric service outages for the Illinois Commerce Commission. Responsible for investigating and analyzing ComEd's capital budgeting, resource allocation, project management, expenditure levels and rate base impacts over 10 years for operations leading up to and in response to the outages.

Lead Consultant on capital expenditure and operating expense benchmarking, capital and expense budgeting, and financial projections included in the restructuring plan for Northwestern Energy – Montana. Liberty performed a management and operations review of the electric and natural gas businesses of Northwestern – Montana following the bankruptcy filing of the utility holding company.

Team leader for the review of the New York Power Authority's (NYPA) profitability, financial reporting, rate competitiveness, pricing policies, power plant economics and economic development programs in two separate management audits for the state of New York. NYPA is the largest generator and carrier of power in New York, providing over 25 percent of the electricity sold.

Led the review of finance, cash management, budgeting, and rates in a comprehensive management audit of Southern Connecticut Gas (SCG) for the Connecticut Department of Public Utility Control (DPUC). Responsibilities included operational audits of all finance, regulatory, pension and budgeting processes of SCG.

Led the review of the finance, cash management, budgets, pension, accounting and rate functions in a comprehensive management audit of Connecticut Natural Gas (CNG) for the Connecticut DPUC. Work also included a focus on the financial impacts of CNG's non-regulated businesses, which includes a large steam system in downtown Hartford.

Led the review of the finance, cash management, budgeting, pension, rates, and tax functions in a comprehensive management audit of Yankee Gas for the Connecticut DPUC. Evaluation included an in-depth analysis of the effectiveness of Yankee's capital and expense budgeting processes and the integration of market and competitive components into these processes.

Led the review of the finance, pension, regulatory and accounting functions in a management audit of United Cities Gas for the Tennessee Regulatory Authority. Responsibilities included a review of all financial functional areas, as well as a review of the impact of all affiliate transactions between the regulated and non-regulated businesses.

Consultant on Liberty's management audit of GTE South - Kentucky for the Kentucky Public Service Commission. Responsible for the analysis of the financial management of GTE as it relates to the operation of its GTE South subsidiary.

Lead Consultant in Liberty's management audit of Bell Atlantic - Pennsylvania and Bell Atlantic - District of Columbia for their respective commissions. Responsible for reviewing Bell Atlantic's capital structure, finance and controller functions, financial systems, and treasury operations.

Energy Supply and Fuel

Lead Consultant in examining purchased power, off-system sales and generation modeling in Liberty's project evaluating the fuel and power procurement and fuel recovery mechanisms of Arizona Public Service for the Arizona Corporation Commission. Responsibilities also included the preparation and submittal of testimony for the regulatory dockets on these issues.

Lead Consultant for Liberty's audit of Arizona Electric Power Cooperative for the Arizona Corporation Commission. Responsibilities included reviews of fuel procurement and management, bulk electricity purchases and sales, power plant management, operations and maintenance, energy clause design and operation, and other issues affecting the prudence, reasonableness, and accuracy of costs that pass through the fuel and energy clause.

Lead Consultant for an audit of Southwestern Public Service for the New Mexico Public Regulation Commission that included a management review of the prudence of SPS' transactions under the fuel clause and a review of purchased power and energy supply economics.

Lead Consultant for evaluating the fuel forecasting models and methods utilized by Nova Scotia Power Company in the development of a fuel adjustment clause mechanism for the company, working for the Nova Scotia Utility and Review Board (UARB). Assessed NSPI's simulated production dispatch model and several ancillary models that include the impact on fuel expense of hedging and ancillary fuel costs.

Lead Consultant for evaluating the electric supply of Mississippi Power for the Mississippi Public Service Commission. Responsible for assessing the Southern Company intercompany interchange agreement, related system operations, power pool purchases and sales and pricing/billing.

Lead Consultant for evaluating the electric supply of Entergy-Mississippi for the Mississippi PSC. Responsible for assessing the Entergy interchange agreements, power pool purchases, electric supply solicitation processes and analysis and pricing/billing.

Lead Consultant for an audit of the gas cost adjustment clauses of Questar for the Public Service Commission of Utah. Responsible for assessing all gas purchase contracts, purchases from affiliate production companies and the financial and credit effects of the gas purchase contracts.

Lead Consultant for evaluating the economic dispatch operations, electric purchases and sales, Independent Power Producer contracts and power imports of Nova Scotia Power Company in a rate case context, working for the Nova Scotia UARB.

Lead Consultant for an audit of the gas cost adjustment clause of CenterPoint Energy for the Minnesota Public Utilities Commission. Responsible for assessing all gas purchase contracts, unbilled revenue impacts and a financial restatement of gas costs by the company.

Prepared, filed and provided testimony regarding a large biomass purchased power agreement of Nova Scotia Power Company, working for the Nova Scotia UARB. Testimony included the evaluation of financial risks, credit rating impact, and contract terms as they would affect NSPI.

Provided in-depth analysis and direct counsel to Commissioners regarding proposals of merchant power companies to build 550 MW power plants and sell all electric output to Mid-American Energy, working for the Iowa Utilities Board. Evaluations included the assessment of financial risks, credit rating impact, economics versus company ownership and contract terms as they would affect Mid-American.

Led the consulting and monitoring of contracting for electric supply by Western Massachusetts Power following the sale of its generation assets under electric deregulation.

Project Leader for the evaluation of electric supply alternatives for Orlando Utilities. Responsible for evaluating electric generation economics, electric purchases and sales, independent power producer contracts, regional market opportunities and transmission paths available.

Mergers and Acquisitions

Lead Consultant for Liberty's audit for the Virginia State Corporation Staff of Potomac Edison's distribution system transfer to two cooperative systems. Liberty examined the public interest, financial, rates and energy supply questions associated with the transfer by Allegheny Energy's utility operating subsidiary (Potomac Electric) of all of its electricity distribution operations business and facilities in Virginia to two rural electric cooperatives.

Served as Liberty's lead consultant in evaluations and testimony regarding the acquisitions of TXU (Texas), UniSource (Arizona) and Portland General Electric (Oregon) by leveraged buyout entities. Responsible for assessments of utility financial insulation and ring fencing, holding company leverage levels and credit rating impacts, governance, service reliability, access to information, and community presence issues.

Lead Consultant for the New Hampshire Public Utilities Commission in the evaluation and negotiation of approval terms for the spin-off and merger of Verizon's New England wireline businesses with FairPoint Communications. Responsible for the review and evaluation of the merger transaction, the financial viability of the merged entity, financial forecasts, credit ratings, access to capital, debt covenant approval and tax implications.

Lead Consultant for financial issues in a focused review of the Exelon/PSEG merger for the New Jersey Board of Public Utilities (BPU). Responsible for defining and evaluating the financing, credit rating, liquidity facility, and market risk exposures of PSE&G's utility operations to risks of Exelon's nuclear generating business.

Rates and Regulatory

Lead Consultant for financial issues in Liberty's benchmarking study of Arizona Public Service Company for the Arizona Corporation Commission. Responsible for designing and implementing the financial evaluation and industry benchmarking of APS' financial performance, cash flow metrics, financial risk measures and credit ratings.

Prepared and filed Liberty's direct testimony addressing rate of return, cost of capital and target debt coverage rates in the 2010 rate cases of Arizona Electric Power Company and Southwest Transmission Company for the Arizona Corporation Commission.

Project Manager for the development and implementation of regulatory financial systems and models for deregulated ratemaking at Pacific Gas and Electric Company. The project involved developing regulatory strategy, California Public Utilities Commission earnings monitoring models, data bases, analytical models and reporting for all regulatory requirements of PG&E's regulated businesses.

Project Leader for Liberty's evaluation of cost of capital issues for a Yankee Gas rate case for the Connecticut DPUC. Scope of work included the analysis of the cost of equity and debt, capital structure, and short-term debt positions of all parties and participation in hearings and drafting of the Staff recommendations regarding Yankee's cost of capital.

Prepared and filed Liberty's direct testimony specifically addressing pension expense and prepaid pension assets in rate base in the 2011 gas rate case of Nova Scotia Power Company for the Nova Scotia UARB.

Prepared and filed direct testimony specifically addressing pension expense and prepaid pension assets in rate base in the 2011 gas rate case of Xcel Energy – Colorado for the Staff of the Public Utilities Commission of the State of Colorado.

Led Liberty's development of a framework and strategy to resolve all electric industry restructuring issues between the State of New Hampshire, Public Service Company of New Hampshire, and the New Hampshire Public Utilities Commission. Project included assessment and valuation of all key assets and development of a disposition strategy for all generation assets, contracts and obligations. The project also included the assessment of alternative rate paths; planning for the securitization and recovery of stranded costs; and the development of provisions for power supply purchases during a transition period.

Lead Consultant in Liberty's financial audit for ratemaking purposes of Verizon New Hampshire (VNH) for the New Hampshire Public Utilities Commission. Responsible for a broad and comprehensive analysis of the financial status of VNH, including an audit of the books and records of the Verizon parent, in order to assist the commission in determining rate base, rates of return and appropriate adjustments for the test year.

Lead Consultant in Liberty's review of the financial integrity and earnings of Verizon New Jersey's (VNJ) rate regulated and competitive businesses for the New Jersey BPU. Responsible for the financial evaluation of VNJ's earnings, capital structure, rates of return, dividend policies, credit ratings, financial reporting, SEC reporting, and BPU surveillance reports.

Team Leader in providing consulting assistance to Kentucky Utilities (KU) in preparing its initial application for implementing an environmental surcharge. Responsibilities included analyzing legislation, analysis of capital expenditures, analysis of KU's Clean Air Act compliance plan, analysis of costs recoverable under the surcharge, and developing testimony, exhibits, special accounting systems, and rate tariffs.

Project Leader for providing consulting assistance to Big Rivers Electric in preparing its initial application for implementing an environmental surcharge. Responsibilities included a review and evaluation of the economics of a major investment in a flue gas scrubber, analysis of Big Rivers' Clean Air Act compliance plan, evaluating cost recoverable under the surcharge, and developing surcharge testimony, exhibits, accounting systems and rate tariffs.

Utility Financial Insulation/Ring Fencing

Lead Consultant for Liberty's two separate, comprehensive affiliate relationships and transactions reviews of Duke Energy Carolinas for the North Carolina Utilities Commission staff, and one review for the Indiana Utility Regulatory Commission. Responsibilities included the review of the Duke Energy/Cinergy merger costs to achieve and merger savings, and the separation of holding company and utility financing, cash management and pension plans.

Lead Consultant for the performance of Liberty's audit and testimony for the Delaware Public Service Commission of the affiliate financial costs and risks borne by Delmarva Power, a member of the multi-state holding company, PHI.

Lead Consultant for Liberty's comprehensive review of affiliate relationships, holding company cost allocation, transaction review, and regulatory reporting and rate recovery for a major Northeastern utility holding company. Responsibilities included the review of the holding company organization and management, transactions with its utilities, cost assignment, and capital recovery techniques.

Project Lead for Liberty's review of affiliate relationships, treasury operations and lines of credit, holding company cost allocation, transaction review, and regulatory reporting and rate recovery of Delmarva/PHI Holdings for the Delaware PSC. Responsibilities included the review of the holding company organization and management, all financing and intercompany transfers, the review of transactions with its utilities, cost allocations, and regulatory reporting.

Leader for all financial areas in the review of affiliate transactions among Public Service Electric and Gas, its holding company parent, and the extensive diversified businesses of the holding company. Responsible for evaluating PSE&G's consolidated finance functions to determine whether the financial integrity, flexibility, and cost of capital of the regulated utility had been adversely affected by the activities of diversified affiliates. Work included the review and analysis of the long-term financing, cash management, direct and indirect credit support mechanisms, investor relations, and all transactions between and among the affiliates.

Lead for examining all financial issues in a pre-rate case audit of affiliate relations at Nova Scotia Power Company for the Nova Scotia UARB. Responsibilities included the evaluation of financing vehicles, lines of credit, credit ratings, holding company structure, and financial impacts of the holding company on financing costs.

Led the review of financial impacts and the effectiveness of insulation of the utility from parent and non-utility finances on Liberty's management and affiliate transactions audit of Elizabethtown Gas (ETG), its new parent AGL Holdings and all affiliates for the New Jersey Board of Public Utilities. This project included detailed examinations of affiliate relationships, governance, holding company and financing and credit facilities and utility ring-fencing. Also reviewed were strategic planning, capital and expense budgeting and enterprise risk management.

Lead Consultant for examination of financing and utility insulation on Liberty's focused audit of NUI Corporation and NUI Utilities. This audit included a detailed examination of the reasons for poor financial performance of non-utility operations, effect of affiliate operations, including commodity trading on utility credit and finance, downgrades of utility credit beneath investment grade, and retail and wholesale gas supply and trading operations. The audit included detailed examinations of financial results, sources and uses of funds, accounting systems and controls, credit intertwining, cash commingling, and affiliate transactions, among others. Liberty's examination included very detailed, transaction-level analyses of commodities trading undertaken by a utility affiliate both for its own account and for that of utility operations.

Led the review of financial impacts and the effectiveness of insulation of the utility from parent and non-utility on Liberty's focused and general management audit of NJR, New Jersey Natural Gas and affiliates for the New Jersey Board of Public Utilities. This project included detailed examinations of affiliate relationships, governance, financing and utility ring-fencing, compliance with New Jersey EDECA requirements for affiliate separation, protection of confidential information, non-discrimination against third-party competitors with utility affiliates, and other code-of-conduct issues.

Led the review of financial impacts and effectiveness of insulation of the utility from parent and non-utility operations and finances on Liberty's focused and general management audits of SJI, South Jersey Gas, and affiliates for the New Jersey Board of Public Utilities. This project included detailed examinations of affiliate relationships, governance, financing and utility ring-fencing, compliance with New Jersey EDECA requirements for affiliate separation, protection of confidential information, non-discrimination against third-party competitors with utility affiliates, and other code-of-conduct issues.

Led the evaluation of the financial relationships between Hawaiian Electric Industries and Hawaiian Electric Company for the Hawaii Department of Commerce and Consumer Affairs. The focus of the review was the credit and financial support provided by the utility company to the holding company and its diversified businesses.

Led the review and analysis of corporate governance, financial relationships and affiliate transactions between Virginia Power and its parent, Dominion Resources for the Virginia State Corporation Commission. The review included an evaluation of all utility and non-utility financing, governance and economic impacts. The engagement was in response to a well-publicized dispute between the holding company and Virginia Power.

Other

Led the review and evaluation of the financial management practices of a major utility holding company. Engagement included an assessment of overall financial management and crisis-liquidity plans; strategic and business planning; asset valuations and their accounting impacts upon deregulation; independent power contract buy-downs; and rate reduction strategies.

Led the evaluation and recommendation of strategic lines of business for a major municipal utility facing industry deregulation.

Led the development of a strategic framework for the establishment and growth of non-regulated businesses for a major international electric holding company.

Led the development, analysis, and recommendation of alternative electric generation and power resource strategies for a regional generation and transmission company in preparation for electric deregulation.

Led the review and evaluation of all utility and non-utility financing, financial relationships, and affiliate transactions between a major utility holding company and its electric company subsidiary.

Leader for all financial areas in the evaluation of the diversified businesses of a major utility holding company. Engagement determined the impact on financial integrity, financial flexibility, credit mechanisms, and the cost of capital of the substantially diversified businesses of the holding company.

Led the development of an overall gas business strategy, capital asset allocation methods, financial analysis programs and gas main extension policy for a Midwestern combination utility.

Education

M.B.A., Finance, University of Denver
B.A., Business Administration, Monmouth College

Arizona Electric Power Cooperative, Inc.

Computation of TIER, DSC, Equity Ratio and Rate of Return

Sources: RUS Form 12

Twelve Months Ended December 31, 2008, 2009, 2010, 2011 and 2012

Line	Description	RUS FORM 12 12 Mos. Ended 12/31/08	RUS FORM 12 12 Mos. Ended 12/31/09	RUS FORM 12 12 Mos. Ended 12/31/10	RUS FORM 12 12 Mos. Ended 12/31/11	Preliminary 12 Mos. Ended 12/31/12
1	Times Interest Earned Ratio Calculation:					
2	Net Patronage Capital or Margins	$ 17,355,771	$ 9,956,925	$ 9,503,555	$ 1,855,188	$ 5,084,009
3	Interest on Long-Term Debt	10,459,715	10,622,133	10,770,431	10,518,102	9,075,209
4	Total	$ 27,815,486	$ 20,579,058	$ 20,273,986	$ 12,373,290	$ 14,159,218
5						
6	Times Interest Earned Ratio	2.66	1.94	1.88	1.18	1.56
7	Average of Two out of Three Highest Years					1.72
8						
9	Debt Service Coverage Ratio Calculation:					
10	Net Patronage Capital or Margins	$ 17,355,771	$ 9,956,925	$ 9,503,555	$ 1,855,188	$ 5,084,009
11	Depreciation & Amortization Expense	8,069,925	8,818,475	9,502,433	9,951,210	10,344,934
12	Interest on Long-Term Debt	10,459,715	10,622,133	10,770,431	10,518,102	9,075,209
13	Total	$ 35,885,411	$ 29,397,533	$ 29,776,419	$ 22,324,500	$ 24,504,152
14						
15	Principal Payments	$ 16,478,234	$ 6,673,550	$ 7,214,074	$ 8,177,084	$ 9,589,123
16	Interest on Long Term Debt	10,459,715	10,622,133	10,770,431	10,518,102	9,075,209
17	Total	$ 26,937,949	$ 17,295,683	$ 17,984,505	$ 18,695,186	$ 18,664,332
18						
19	Debt Service Coverage Ratio	1.33	1.70	1.66	1.19	1.31
20	Average of Two out of Three Highest Years					1.48
21						
22	Equity as a Percent of Total Capitalization:					
23	Equity and Margins	$ 74,558,070	$ 84,514,994	$ 94,018,553	$ 95,873,741	$ 100,493,944
24	Long Term Debt (Including Current Portion)	179,189,648	180,049,657	195,368,110	225,476,378	187,110,214
25	Short Term Debt	17,534,537	22,442,010	9,747,026	3,721,518	4,067,238
26	Total Capitalization	$ 271,282,255	$ 287,006,661	$ 299,133,689	$ 325,071,637	$ 291,671,396
27						
28	Equity - Percent of Capitalization	27.48%	29.45%	31.43%	29.49%	34.45%
29						
30	Funds From Operations/ Interest on Long Term Debt:					
31	Operating Margins	$ 16,506,717	$ 8,368,103	$ 8,398,756	$ 829,142	$ 1,792,374
32	Plus:					
33	Depreciation and Amortization	8,069,925	8,818,475	9,367,223	9,951,210	10,344,934
34	Funds From Operations	$ 24,576,642	$ 17,186,578	$ 17,765,979	$ 10,780,352	$ 12,137,308
35						
36	Interest on Long Term Debt	$ 10,459,715	$ 10,622,133	$ 10,770,431	$ 10,518,102	$ 9,075,209
37						
38	FFO/Interest Coverage	3.35	2.62	2.65	2.02	2.34
39						
40	Long Term Debt (Including Current Portion)	$ 179,189,648	$ 180,049,657	$ 195,368,110	$ 225,476,378	$ 187,110,214
41	Obligations Under Capital Lease (Including Current Portion)	5,912,238	5,486,601	4,088,429	2,563,182	1,075,072
42	Notes Payable	17,534,537	22,442,010	9,747,026	3,721,518	4,067,238
43	Total Debt	$ 202,636,423	$ 207,978,268	$ 209,203,565	$ 231,761,078	$ 192,252,524
44						
45	FFO/Debt	12.13%	8.26%	8.49%	4.65%	6.31%
46						

Moody's Financial Metrics for Electric G&T Cooperatives
(40% of Evaluation)

	A ***A Rated Range***	B ***AEPCO 3-year Historical Average (2010-2012)***
Funds From Operations/Debt (FFO/Debt)	6% -10%	6.48%
Funds From Operations/Interest (FFO/Interest)	2.0X - 2.5X	2.34X
Equity/Total Capitalization	20% - 35%	31.79%
Debt Service Coverage (DSC)	1.2X - 1.4X	1.39X
Times Interest Earned Ratio (TIER)	1.2X - 1.4X	1.54X

Column A from response to REV 1.6, "U.S. Electric Generation & Transmission Cooperatives", Moody's Investors Service, December 2009.
Column B calculated from the response to REV 5.1, AEPCO financial results for 2008-2012.

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01773A-12-0305

REDACTED

DIRECT

TESTIMONY

OF

DENNIS M. KALBARCZYK

(CONSULTANT)

ON BEHALF OF THE STAFF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MAY 1, 2013

TABLE OF CONTENTS

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Dennis M. Kalbarczyk. My business address is 910 Piketown Road, Harrisburg, Pennsylvania 17112.

Q. By whom are you employed and in what capacity?

A. I am the principal of Utility Rate Resources, and work frequently with the Liberty Consulting Group, Inc. ("Liberty"),. Liberty has been engaged by the Arizona Corporation Commission ("ACC" or "Commission") to assist the Utilities Division ("Staff") in the review of the Arizona Electric Power Cooperative Inc.'s ("AEPCO" or "Cooperative") application for a general rate increase in the proceeding at Docket No. E-01773A-12-0305.

Q. Briefly summarize your education background and professional qualifications.

A. I graduated in 1971 with a Bachelor of Science Degree in Accounting from Husson College (now Husson University), in Bangor, Maine. In 1969, I received an Associate in Art Degree in Accounting from Strayer College (now Strayer University), in Washington D.C. I am the principal in Utility Rate Resources, which was formed in October 1990. I have prepared over fifty rate case filings, which have included almost all key aspects of the ratemaking process, such as revenue requirement elements (revenues, operation & maintenance expenses, administrative and general expenses, taxes, depreciation and amortization expenses, and rate base valuation); rate of return; cost of service; rate design; and, other specialty tariff rate design matters.

I was employed by Drazen-Brubaker & Associates, Inc. from March 1988 to September 1990. I presented testimony and prepared financial statements necessary for applications for

Certificates of Public Convenience before the Pennsylvania Public Utility Commission ("PaPUC"). Additionally, I was responsible for the preparation and filing of rate cases, and testified on behalf of utilities under PaPUC regulation. Prior to March 1988, I was employed by Metropolitan Edison Company, a subsidiary of First Energy, formerly GPU Energy and General Public Utilities. I spent three years in the utility's Rate Revenue Requirement Department as a Senior Financial Analyst. My responsibilities included the preparation, review, and analysis of financial reports, budgets, and management responsibility for rate and regulatory matters before the PaPUC.

From 1975 through 1985, I was employed by the PaPUC, serving primarily in the performance of financial and operations audits and in rate proceedings. I testified on revenue requirements matters in nearly all the major electric rate cases during my time at the PaPUC, and performed audits of electric, gas, and water companies for compliance with Commission regulations in the areas of energy cost, coal and gas contracts, and affiliated service contracts. I testified in Energy Cost Rate, Gas Cost Rate, and Coal Compliance proceedings. I actively participated in developing the Commission's first set of regulations on Fuel Procurement Policy and Procedures, Tariffs and Procedures on Energy Cost Rates for electric companies and Gas Cost Rates for gas companies, and designed computerized procedures for electric utilities to report fossil fuel purchases to the PaPUC. From 1972 to 1975, I held progressive degrees of responsibilities with Certified Public Accounting firms performing accounting, auditing and tax preparation duties.

I have specialized in the area of utility rate and economic consulting related to the financial aspects of public utility rates and regulation. My work has encompassed rate case filings, certificates of public convenience, expert testimony, and financial applications for funding by the Pennsylvania Infrastructure Investment Authority. I have participated in regulatory and legal proceedings concerning investor-owned and municipal utilities, have testified before governmental agencies and courts, and have represented utilities as well as consumers of utility services.

Since 2002, I have been providing senior level consulting services to Liberty, participating in an audit of electricity distribution service costs for inclusion in revenue requirement before the Illinois Commerce Commission, and serving as a team member on focused audits (for the New Jersey Board of Public Utilities) addressing financing, accounting, and affiliate charges of National Utilities Inc. (Elizabethtown Gas), South Jersey Gas, and New Jersey Natural Gas. I participated in Liberty examinations of fuel adjustment mechanism costs and issues for staffs of the Arizona Corporation Commission and the Nova Scotia Utility and Review Board ("NSUARB"). I also participated in Liberty's engagements to assist Staff in the review of AEPCO's and the Southwest Transmission Cooperative, Inc. ("SWTC") applications for a general rate increase in the proceedings at Docket Nos. E-01773A-09-0472 and E-04100A-09-0496 pertaining to cost of service and rate design matters, respectively and testified to same. I also participated with Liberty in Nova Scotia Power Incorporated's last two general rate increase filings pertaining to revenue requirement matters, and testified to same. I have testified in more than 70 rate and regulatory matters on behalf of state regulatory commissions, utilities, municipal authorities, and various consumer groups.

Q. What is the purpose of your testimony?

A. I am addressing, on behalf of the Staff, AEPCO's revenue requirement request and the fully allocated cost of service study and proposed rate design as submitted by AEPCO witnesses Peter Scott and Gary E. Pierson. With regard to various elements of AEPCO's revenue requirement request, I will also be relying upon the review and recommendations of other Liberty team members involved in the instant proceeding. I provide the following brief summary of the area of responsibilities of the Liberty team members. Mr. Vickroy addresses the overall rate of return component related to the net income component level to be factored into the determination of revenue requirement. Mr. John Antonuk testifies on fuel and purchase power matters along with corresponding recommendations in this area. Mr. Mazzini performed an engineering review of the AEPCO generating facilities; thus, reliance upon his findings and recommendations are relevant in-part to plant and depreciation matters, as well as related operation and maintenance criteria related to same.

II. INTRODUCTION AND BACKGROUND

Q. Briefly state your understanding of the nature of this proceeding?

A. On July 5, 2013, AEPCO filed a general rate application with the Commission, requesting an overall revenue <u>decrease</u> of approximately $4.527 million to its pro forma adjusted December 31, 2011, test year present rate revenues. AEPCO proposed an effective date of November 1, 2013, for these new rates, which, as filed, would produce a 2.92 percent <u>decrease</u> to proposed rate revenues. Table 1 below reflects the major revenue requirement elements within AEPCO's filing; i.e., operation and maintenance expenses, depreciation and amortization expenses, taxes, and net income. For ratemaking purposes, the overall rate of return is expressed as percentage of net income over rate base values; i.e., net plant-in-service values and other investment values such as fuel and material and supplies stock.

As illustrated, reclassified per book revenues and expenses of $166.5 and $154.5 million would produce $11.9 million of net income and a 4.42 percent overall rate of return when divided by $270.7 million of rate base. On a pro forma adjusted basis, revenues of $163.6

minus expenses of $148.4 million would produce $15.2 million of net income and a 5.68 percent overall rate of return when divided by $267.5 million of pro forma rate base. Thus, a $4.5 million reduction to revenues and net income would produce a 3.99 percent rate of return ($10.7 million adjusted net income divided by same $267.5 million rate base).

Table 1 – Summary of As-Filed Revenue Requirements

	Reclassified Per Books	Pro Forma Adjustments	Pro Forma Present	Change In Revenues	Pro Forma Proposed
Class A Members	$155,209,979	($ 285,108)	$154,924,873	($4,527,465)	$150,397,406
Non-CLS A, N-Firm/Member	$5,855,043	($2,951,958)	$2,903,085	$0	2,903,085
Other Operating	$5,463,417	$333,227	$5,796,644	$0	$5,796,644
Total Revenues	$166,528,439	($2,903,839)	$163,624,600	($4,527,465)	$159,097,135
Oper. & Maint.	$142,342,953	($9,541,665)	$132,801,288	$0	$132,801,288
Depr & Amort.	$9,951,210	$3,398,294	$13,349,504	$0	$ 3,349,504
Taxes	$2,269,687	$0	$2,269,687	$0	$2,269,687
Total Expenses	$154,563,850	($6,143,371)	$148,420,479	$0	$148,420,479
Oper. Net Income	$ 11,964,589	$3,239,532	$ 15,204,121	($4,527,465)	$ 10,676,656
Plant-In-Service	$452,704,132	($ 13,328)	$452,690,894	$0	$452,690,894
Accum. Depr.	($210,318,467)	($3,398,294)	($213,716,761)	$0	($213,716,761)
Accum. Amort.	($6,428,568)	$166,973	($6,261,595)	$0	($6,261,595)
Net Plant	$235,957,097	($3,244,559)	$232,712,538	$0	$232,712,538
Fuel Stock	$26,371,847	$0	$26,371,847	$0	$26,371,847
Mat. & Suppl.	$8,397,175	($17,973)	$8,379,202	$0	$8,379,202
Rate Base	$270,726,119	($3,262,532)	$267,463,587	$0	$267,463,587
Rate of Return	4.42%		5.68%		3.99%

The preceding discussion takes a traditional ratemaking approach based upon an overall rate of return calculation. The revenue requirements of AEPCO, as a cooperative, are driven by the necessary margins available to maintain adequate Debt Service Coverage ("DSC") and Total Interest Earned Ratio ("TIER"). The next table shows AEPCO's per books and pro forma present and proposed DSC and TIER ratios. AEPCO's as-filed proposed DSC ratio of 1.32 times would reflect a $6 million ($24.6 - $18.6) margin above long-term debt service requirements; see the next table.

Table 2 – Summary of As-Filed Debt Service Coverage Requirements					
	Reclassified Per Books	Pro Forma Adjustments	Pro Forma Present	Change In Revenues	Pro Forma Proposed
Oper. Net Income	$11,964,589	$3,239,532	$15,204,121	($4,527,465)	$10,676,656
Int. & Other Ded.	($11,135,447)	$1,389,966	($9,745,481)	$0	($9,745,481)
Other Income	$1,026,046	$0	$1,026,046	$0	$1,026,046
Net Margin	$1,855,188	$4,629,498	$ 6,484,686	($4,527,465)	$1,957,221
Depr. & Amort.	$9,951,210	$3,398,294	$13,349,504	$0	$13,349,504
Int. On L/T Debt	$10,518,102	($1,236,231)	$9,281,871	$0	$9,281,871
Available Funds	$22,324,500	$6,791,561	$29,116,061	($4,527,465)	$24,588,596
P&I on L/T Debt	$18,695,352	($ 67,628)	$18,627,724	$0	$18,627,724
DSC	1.19		1.56		1.32
TIER (Net Margin + Int LT Debt / Int LT Debt)	1.18		1.70		1.21

AEPCO's last rate case was filed on October 1, 2009, in Docket No. E-01773A-09-0472. Commission Decision No. 72055 authorized new rates that went into effect on January 1, 2011. On October 20, 2011, AEPCO filed an application requesting to reopen and amend the prior order, to correct minor errors in the calculation of rates attributable to the allocation of fixed gas costs. The January 6, 2012, Commission Decision No. 72735 approved the change requested by AEPCO.

Q. Whom does AEPCO serve?

A. AEPCO is a not-for-profit generation cooperative providing wholesale power needs to three Collective All-Requirements Members ("CARM") Class A members: Duncan Valley Electric Cooperative, Inc. (Arizona), Graham County Electric Cooperative, Inc. (Arizona), and Anza Electric Cooperative (south-central California). AEPCO also provides service to three Partial-Requirement Members ("PRM"), Class A distribution cooperatives: Mohave Electric Cooperative, Inc., ("MEC"), Sulphur Springs Valley Electric Cooperative, Inc. ("SSVEC"), and Trico Electric Cooperative, Inc. ("TRICO").

Q. Please summarize the requested change in rates.

A. Table 3 below compares present rates to those proposed. Generally, CARM and PRM revenues will decrease by 1.30 percent and 3.12 percent, respectively, combining to produce a net revenue decrease of 2.92 percent.

Table 3 – Comparison of Present and Proposed Rates $ and % Increase/(Decrease)				
	Present	Proposed	$Inc/(Dec)	%Inc/(Dec)
Collective All-Requirement Members				
Fixed Monthly Charge	$273,334	$280,598	$ 7,264	2.66%
O&M Monthly Charge	$414,019	$458,175	$ 44,156	10.67%
Base Resources Energy Charge/kWh	$0.03132	$0.02921	($0.00211)	(6.74%)
Other Existing Resources Charge/kWh	$0.05300	$0.04795	($0.00505)	(9.53%)
Partial-Requirements Members				
Mohave Electric Cooperative				
Fixed Monthly Charge	$ 835,756	$ 856,335	$ 20,579	2.46%
O&M Monthly Charge	$1,274,882	$1,419,059	$ 144,177	11.31%
Base Resources Energy Charge/kWh	$ 0.03191	$ 0.02894	($0.00297)	(9.31%)
Other Existing Resources Charge/kWh	$ 0.05852	$ 0.05437	($0.00415)	(7.09%)
Sulphur Springs Valley Electric Cooperative				
Fixed Monthly Charge	$ 740,041	$ 758,281	$ 18,240	2.46%
O&M Monthly Charge	$1,128,876	$1,256,541	$ 127,665	11.31%
Base Resources Energy Charge/kWh	$ 0.03205	$ 0.02938	($0.00267)	(8.33%)
Other Existing Resources Charge/kWh	$ 0.05742	$ 0.05109	($0.00633)	(11.02%)
TRICO Electric Cooperative				
Fixed Monthly Charge	$ 710,367	$ 743,828	$ 33,461	4.71%
O&M Monthly Charge	$ 764,465	$ 859,840	$ 95,375	12.48%
Base Resources Energy Charge/kWh	$ 0.03214	$ 0.02947	($0.00267)	(8.31%)
Other Existing Resources Charge/kWh	$ 0.05747	$ 0.04219	($0.01528)	(26.59%)

III. REVENUE REQUIREMENT

Q. What general concepts were applied in Liberty's review of AEPCO's revenue requirement request?

A. AEPCO based its revenue requirement on an historic test year ended December 31, 2011. AEPCO made adjustments on a pro forma basis to reflect known and measurable changes to operations on normalized going forward basis. The ratemaking approach in Arizona, which is similar to that of other state utility regulatory authorities, seeks to match investments and expenses required to provide regulated service, in order to identify the corresponding revenues required to provide a margin appropriate for providing a reasonable opportunity for return on investment similar to like businesses facing similar risks. Further, investments (rate base net plant, related fuel stock, and materials and supplies) and expenses must be used and useful, necessary for the conduct of business, and costs must be prudent and reasonable. Finally, the ratemaking process also provides that costs that fluctuate be normalized or averaged, and that extraordinary or non-recurring costs be amortized where appropriate for recovery over time through the rate setting process.

Liberty considered all of these factors in its review of AEPCO's identification of its total revenue requirement needs. Liberty reviewed all pro forma adjustments, and tested them for reasonableness, and examined other major cost components used to develop the total cost of service or revenue requirement needs.

Q. Please summarize AEPCO's reasons for the proposed revenue requirement decrease.

A. Table 4 below provides a brief summary of the major pro forma adjustments and changes in operations that affect AEPCO's proposed revenue decrease of $4.5 million. Liberty reviewed each of the proposed adjustments and the table notes its acceptance or rejection. Liberty also proposes additional adjustments, as discussed below. AEPCO's pro forma adjustments affect both income statement items (revenue and expense) and plant-investment values (rate base). For example, AEPCO's filing reflects a $3.2 million net increase in depreciation expenses, based upon an outside firm's study of the Apache station. Adjustments resulting from this study affect revenue requirements associated with expenses and rate base.

Table 4 – Summary of AEPCO Pro Forma Adjustments					
1.	ED2 Contract Termination	Electrical Dist. 2 8MW contract expires on 9/20/12	Operating revenues, fuel and transmission expenses, net margin decreased	($1,397,636)	Accepted
2.	Coal Cost Expense Adj.	AEPCO initiated litigation of rail rates, and received an award of $9.2 million in reparations which are under appeal	Fuel Prod. Cost expenses reduced on a going forward basis	$10,967,627	Accepted (See additional adjustments and comment)
3.	Fixed Gas Chrg. Adj.		Fuel Prod. Cost expenses reduced on going forward basis	$48,153	Accepted
4.	Payroll & Overheads Adj.		Var. O&M Prod./Other/ cost expenses reduced on going forward basis	$2,289,963	Accepted (See Liberty Comment)
5.	Maint. Outage Overhaul Adj.		Maint. Prod./Other reduced on going forward basis	$411,246	Accepted (See Liberty Comment)
6.	Point-To-Point Wheeling Adj.		Oper. Transmission Cost increase	($6,226,200)	Accepted
7.	Scheduling & Trading SVCS Adj.		Operating revenue increase	$333,227	Accepted
8.	APM Regional Trading Center Adj.		Increase in Prod./Other Power Supply Energy costs	($870,278)	Accepted
9.	Cost Cutting Programs		Decrease in O&M Production expenses for cost cutting initiatives	$764,000	Accepted (See Liberty Comment)
10.	Amortize Rate Case Exp.		3-Year Amortization of Instant $240,000 Rate Case Expense Claim	($80,000)	Accepted (See Liberty Comment)
11.	Calif. Parties Legal Cost Adj.		Decrease A&G legal non-recurring legal expenses	$1,212,332	Accepted
12.	Southpoint PPA Capacity Adj.		Increase Operating/Other Pwr. Supply Energy expenses	($529,500)	Accepted
13.	Depr./Amort.		Inc. Depr./Dec. Other Ded. Inc. Net Exp. Inc.	($3,398,294) $ 153,735 ($3,244,559)	Accepted in-part (Comment) Accepted
14.	Cut Debt Ref. Adj.		Reduce Interest exp. refinancing	$531,768	Accepted
15.	Int. Annualization Adj.		Reduce Interest Expense	$704,463	Accepted

16.	Rev. Synch. Adj.		Class A-M Rev. Inc. Fuel Adj Rev. Dec. Net Rev. Dec.	$1,440,980 ($1,726,088) ($ 285,108)	Accepted Accepted
	Total Change In Margin			$4,629,498	

IV. RATE BASE ELEMENTS

Q. What is the significance of rate base value and annual depreciation expense claim as it pertains to the Apache station and the outside study?

A. AEPCO witness Peter Scott at pages 5 and 6 of his testimony notes that one of the major reasons for the rate decrease filing is a request to revise its depreciation rates as supported by the outside study. AEPCO Exhibit PS-2 addresses this assessment of the gas and coal fired units at the Apache Station. The Apache station represents $204.8 million of the $232.7 million pro forma net original cost book investment or rate base value claimed (original cost less accumulated depreciation). This sum equals 88 percent of total pro forma net original cost rate base value.

Table 5 – Plant-In-Service Values, Including Apache Station Details

	Orig. Cost	12/31/11 Accum. Depr	12/31/11 Book Value	Pro Forma Adj.	Net Orig.Cost RB Value
Apache					
ST1*	$25,838,145	($20,613,365)	$5,224,780	$282,280	$5,507,060
ST2	$172,173,556	($85,968,233)	$86,205,326	($1,870,841)	$84,334,485
ST3	$167,167,698	($75,833,026)	$91,334,673	($1,997,614)	$89,337,058
IC 1*	$2,302,908	($1,852,641)	$450,268	$(7,648)	$442,619
IC 2*	$2,961,842	($2,802,753)	$159,089	$95,355	$254,444
IC 3*	$8,745,051	($6,904,979)	$1,840,073	$114,391	$1,954,463
GT 4	$29,957,618	($7,013,761)	$22,943,857	($14,215)	$22,929,641
Total	$409,146,821	($200,988,757)	$208,158,064	($3,398,294)	$204,759,770
Other	$43,557,311	($15,748,278)	$27,799,033	$166,973	$27,952,768
All Plant	$452,704,132	($216,747,035)	$235,957,097	($3,244,559)	$232,712,538
* Estimated end life 12/31/2020; remaining units 12/31/2035					

Apache's pro forma depreciation expense claim of $11.2 million represents 84 percent of the total annual expense claim ($13.3 million).

Table 6 – Depreciation Expense Values, Including Apache Station Details					
	2011 Depr.	Pro Forma Change In Depr.	Decomm/Salvage	NetChange	Pro Forma Depr.
ST1*	$801,500	($284,103)	$1,822	($282,280)	$519,220
ST2	$2,765,647	$879,129	$991,713	$1,870,841	$4,636,488
ST3	$2,863,240	$1,05,815	$991,799	$1,997,614	$4,860,854
IC 1*	$44,703	$6,848	$800	$7,648	$52,352
IC 2*	$90,297	($93,364)	($1,986)	($95,355)	($5,058)
IC 3*	$296,902	($118,863)	$4,473	($114,391)	$182,511
GT 4	$933,876	$24,129	($9,914)	$14,215	$948,091
Total	$7,796,164	$1,419,587	$1,978,707	$3,398,294	$11,194,458
Other	$2,155,046				$2,155,046
All Plant	$9,951,210				$13,349,504
* Estimated end life 12/31/2020; remaining units 12/31/2035					

Traditional ratemaking concepts would translate these values into a $19.4 million annual revenue requirement. The first element would provide a margin of $8.2 million ($204.8 million x 3.99 percent rate of return). The second element would consist of $11.2 million of annual deprecation expenses. The outside study led to an AEPCO determination of $1.4 million in increased annual depreciation expense. Beyond this increase, AEPCO has also, for the first time, requested almost $2 million of new annual revenue requirements to fund $43.5 million of estimated net decommission costs ($61 million estimated decommission cost less $14.4 million of estimated salvage and $3.1 million in Asset retirement obligation liabilities).

Apache Units ST1, IC 1, 2, and 3 have 72, 10, 20, and 60 MW's of capacity, respectively. AEPCO identifies for its combined 162 MWs an end date of December 31, 2020. Thus, 28 percent of the 560 total MW capacity of Apache will have but seven remaining years left after the proposed effective date of November 2013 for new rates.

Liberty does not believe that AEPCO has timely and effectively addressed matters related to the concern of the economic viability of the Apache station and the potential rate impact on its members. In the prior rate preceding the Liberty team recommended that AEPCO conduct a study as to the future role of the Apache station and how that role relates to member needs for future power supply. Further, the Commission order at paragraph 76 stated:

> *In addition, the Commission believes that AEPCO should include in its study of the future Apache Station an assessment of the potential rate impacts associated with looming Environmental Protection Agency rulemakings regarding mercury emissions, coal ash, and any other known or pending EPA regulatory actions that could impact the Station, AEPCO, and its customers and provide recommendations to the Commission regarding potential methods for mitigating the Cooperative and its customers' exposure to those rate impacts for the Commission's review and consideration.*

Liberty's report of its engineering analysis of AEPCO's facilities describes concerns about AEPCO's lack of timely and sufficient study regarding Apache.

Q. What revenue requirement value is associated with the Apache unit ST1?

A. The margin associated with ST1 is $219,732, or $5,507,060 in net plant value times the proposed 3.99 percent overall rate of return. Annual depreciation and net decommissioning expense amounts to $519,220. Combining the two amounts produces a total ST1 revenue requirement of $738,952.

Q. Were the Commission to determine that the ST1 unit is not used and useful what ratemaking treatment would you recommend?

A. A number of considerations apply when finding assets not to be used or useful. The prior used and useful nature of the asset, the reason for removal, and balancing impacts on customers and utility fall among them. ST1 comprises an asset on which AEPCO did previously rely for service. Present and prior rates have reflected its costs. Were the asset simply reaching the end of its useful life action based on obsolescence, consideration of the following approach may be appropriate. One could deal with obsolescence in a number of ways; *e.g.*, making an allowance for accelerated depreciation, or removal from rate base with amortization over a reasonable period of time. On the other hand, upon a demonstration that the asset could meet some emergency requirements, it could be considered standby and continued to be included in rates. The item could be written off immediately with some provision for partial recovery in rates, to reflect a balance of the interest of both customers and utility.

However, an added concern here results from AEPCO's recent addition of capital investment to ST1 in 2010, after which the unit operated at negligible levels in 2011, and not at all in 2012. A robust AEPCO analysis of the unit's future, as addressed in our engineering report, is compellingly necessary to permit a determination that ST1 has a meaningful future role.

Q. Do you have any other comments with regard to AEPCO's proposed changes in depreciation rates?

A. Yes. Given the nature of the outside study of depreciation, as noted in our engineering report, AEPCO has not laid a proper foundation for using the requested depreciation rates on a going forward basis. In essence, the study only affirmed that the units could continue to meet contract lives extending to 2020 and 2035 for the various Apache units, contingent upon good operations, maintenance and safety practices, and expanded capital required for replacement and refurbishment of equipment. From a ratemaking prospective, Liberty believes that the Commission struck the appropriate balance in the last proceeding when it ordered that an assessment of the potential rate impacts associated with looming issues. That analysis, even before considering EPA concerns, may well have a profound impact on the remaining lives and economic values of the Apache units.

We found no errors in the mathematical calculations of depreciation rates, but the inability to establish remaining unit lives under the circumstances is material. A decision regarding remaining life and related depreciation values impact on the depreciation expense and rate base adjustment claims should be deferred pending the outcome of further AEPCO analysis.

Lastly, AEPCO's proposed adjustment to rate base due to a change in going forward depreciation rates is not appropriate from either an accounting or ratemaking approach. In short, the change does not impact the remaining net book value of the asset. The remaining life concept merely addresses the going forward depreciation rates and corresponding expense necessary to account for the decreasing annual value of the current net book value of the asset. Thus, any proposed change to net book value based upon changes in depreciation rates should be disallowed.

Q. Do you have any other comments with regard to the remaining rate base elements claim?

A. AEPCO's filing reflected a $26,731,847 claim for fuel stock (coal) based upon a 12-month average of 2011 fuel stock values. Liberty reviewed the requested claim in the same context with the 2010 and 2012 fuel stock values. As the next table illustrates, the 12-month average for fuel stock in 2010, 2011, and 2012 was $29,973,060, $26,731,847, and $20,731,198, respectively. The fuel average decreased by $3.6 million (12 percent) from 2010 to 2011, and by $5.6 million (21 percent) from 2011 to 2012.

Table 7 – Coal Inventory Values, By Month 2010-2012 and 2002 Tons				
	2010	2011	2012	2012 Tons
January	$32,730,466	$26,453,614	$19,410,058	[redacted]
February	$34,352,485	$26,144,341	$17,051,822	
March	$33,847,785	$27,435,479	$17,680,773	
April	$36,548,714	$26,940,099	$21,753,935	
May	$34,869,959	$28,368,607	$22,862,955	
June	$29,911,765	$28,783,268	$24,102,203	
July	$28,717,454	$27,670,331	$23,347,567	
August	$26,945,244	$25,727,512	$22,373,204	
September	$24,998,008	$25,993,940	$21,347,989	
October	$25,288,354	$25,656,287	$20,954,523	
November	$25,160,964	$25,064,565	$19,524,974	
December	$26,305,517	$22,224,115	$18,364,368	
Total	$359,676,715	$316,462,158	$248,774,371	
12-mth Avg	$29,973,060	$26,371,847	$20,731,198	
Change		($3,601,213)	($5,640,649)	
% Change		(12%)	(21%)	

Liberty examined the reason for the decreases to determine the reasonableness of the claim being based upon a 2011 average, given the continued decline in average cost and estimates of fuel purchases and consumption.

Q. What is Liberty's opinion with regard to fuel stock value and inventory levels claimed in the instant proceeding?

A. Liberty's opinion is that reliance upon 12-month average of fuel stock value based upon 2011 stock values or claim of $26,371,847 is not representative of going forward costs, based upon known and measurable circumstances. At a minimum, AEPCO should use the 12-month average of 2012 fuel stock ($20,731,198), which would produce a downward adjustment of $5,640,649. Liberty also found that coal inventory levels have continued to be well above target levels since early 2008. AEPCO needs to demonstrate more consistent actions on inventory management with the goal of bringing coal inventory levels down into the target range - 2011 and 2012 actual inventory levels are well above their own required target inventory levels. Liberty proposes an additional [redacted] downward adjustment due to excessive fuel stock inventory levels, for net fuel stock value of [redacted].

Q. **Explain the rationale for decreasing the fuel stock by $5.6 million, or to a value of $20.7 million.**

A. Liberty bases its recommendation upon AEPCO's pro forma downward adjustment #2 of $10,967,627 to coal cost (shown on Schedule C-2, page 3) and the testimony explaining the reason for this adjustment provided by AEPCO witness Gary Pierson (at page 9 of his testimony). Mr. Pierson explains that rail transportation cost decreased significantly in 2012, due in-part to AEPCO's decision to challenge rail rates. Mr. Pierson notes that Surface Transportation Board Decision No. 41181, issued on November 22, 2011, established new lower rail rates for the period 2009 through 2018. Further, the decision awarded AEPCO $9.2 million related to rail transportation costs paid in 2009 through 2011. As a result of the new tariff rates, Mr. Pierson at page 9, line 19 states,

> *AEPCO has been able to negotiate new coal supplies for 2012 at a much lower cost than was recorded in the test period. Taking these new coal commodity rate and rail transportation rates into account AEPCO has included a pro forma reduction in the test year coal expenses of approximately $11 million and, correspondingly, the effect is to increase margins by that amount.*

The 2010 and 2011 coal stock values may have reflected actual values incurred for fuel stock at the time, but it is clear that they are overvalued as a reflection of future costs, based upon the Surface Transportation Board's decision awarding $9.2 million for the 2009 through 2011 period. Also important is that the trend in the reduced coal costs was sufficiently known and measurable for AEPCO to project a lower cost of coal expense on a going forward basis. Liberty accepts AEPCO's downward coal expense adjustment. Moreover, the trended value of inventory illustrated in the table above shows a clear decline in inventory values for what is now two years. Lower inventory levels may have contributed to the reduction of fuel stock values, but those inventory levels remain well above AEPCO's targets.

Q. What is your understanding of the target levels?

A. Liberty conducted a review of fuel stock levels in the prior rate proceeding. Liberty's fuel report in this proceeding provides the following discussion with regard to target levels.

> [redacted] *During that period various power sales contracts were in place, coal prices were more competitive, and member demand for energy was higher. AEPCO has calculated that of the total coal inventory, approximately 20 days of coal, or 66,000 tons are not recoverable, unburnable tonnage.*

Thus, a target of [redacted] tons with a [redacted] percent additional allowance provides a maximum allowance of [redacted] tons. An additional, conservative approach would include consideration of the 66,000 tons of unburnable tonnage, which would increase the maximum allowance to [redacted] tons. This amount remains considerably lower than the [redacted] 12-month average for 2012 (shown in table 7 above). That average level falls approximately [redacted] above the upper band of AEPCO's target.

Q. What does Liberty recommend regarding tonnage inventory levels?

A. Liberty's fuel report recommends that AEPCO begin to take steps to reduce inventory levels. For ratemaking purposes, Liberty recommends a gradual approach, which would further reduce the minimum 2012 inventory level of $20,731,198 downward [redacted], for an allowed ratemaking level of [redacted].

Q. Do you have any final comments with regard to inventory values and AEPCO's proposed reduction to coal cost expenses?

A. Yes. AEPCO's actions to address rail costs before the Surface Transportation Board is commendable, and should produce considerable savings through 2018. Mr. Pierson's testimony notes that the $9.2 million awarded remains a deferred credit until the matter is finally resolved. AEPCO further explains that it will consult with the Commission as to the mechanism to distribute all, or some portion of the final award to its customers. Liberty agrees with AEPCO's proposal.

Q. Did Liberty also review adjustment number 3 included in Table 4 above related to the $48,153 fixed gas charge adjustment?

A. Yes. AEPCO has proposed a reduction in its fixed gas costs, resulting from offsetting changes from Test-Year cost increase of $193,000 in pipeline fixed costs. The cause was an increase in El Paso's rates and a decrease of $241,000 in storage costs, due to a decrease in the amounts of storage services under contract. Both of these changes are considered "known and measurable." Liberty accepts AEPCO's adjustment as filed.

Q. What is Liberty's recommendation regarding AEPCO's materials and supplies rate base value claim?

A. Liberty reviewed the claim, which AEPCO based upon a 12-month average of 2011 values. We examined 2010 and 2012 inventory values, reviewed data request responses, and discussed the issue with AEPCO personnel. We accept this amount as-filed.

V. REVENUE AND EXPENSE ELEMENTS

Q. Please provide an overview of AEPCO's revenue and expense element adjustments that relate to matters that also have an impact on rate base.

A. AEPCO's expense adjustments numbers 2 and 3 relate to coal and gas costs expenses. Adjustment number 13 concerns depreciation expenses. We discussed the underlying issues in our preceding discussion of rate base matters. Liberty's review of the remaining adjustments cover changes in revenues and expenses due to eliminations of various contracts, changes in operations and maintenance expenses, payroll costs, and other ancillary expenses requiring normalization due to fluctuating or nonrecurring costs.

Q. Please discuss AEPCO's adjustment 1, which concerns the expiration of a contract.

A. AEPCO' adjustment 1 removes revenues and expenses due to the expiration of the 8 MW sales of 48 MW point-to-point service contract, related to Electrical District 2 ("ED2"), that expired on September 30, 2012. The adjustment produces a net margin decrease of $1.4 million. Following our review of adjustment 1, we find it appropriate.

Q. Please discuss AEPCO's adjustment 6 which concerns wheeling.

A. Adjustment 6 reflects net increased cost of $6.2 million associated with point-to-point wheeling requirements. On January 1, 2011, AEPCO entered into an additional 50 MW point-to-point service to provide the necessary wheeling path for an N-1 event. On January 1, 2012, the 50 MW contract and remaining 40 MW contract discussed in adjustment 1 (90 MW total) was consolidated into a 110 MW point-to-point service. The consolidation produced an additional 20 MW of increased service and a corresponding additional cost of $925,000. In addition to these requirements, AEPCO also needs 205 MW of additional point-to-point service with SWTC to provide the necessary wheeling paths to meet AEPCO's Southwest Reserve Sharing Group obligation. This additional 205 MW entails a cost of $9,500,000, which produces a combined cost of $10,425,000 when adding the additional 20 MW. The lower rates that SWTC proposes in its current rate request would partially offset this increase. SWTC's proposed lower point-to-point transmission service rates would cause a cost decrease of $4.2 million, making the net change an increase of $6.2 million in expenses. Liberty's review of this adjustment found it to be appropriate.

Q. Please discuss AEPCO's adjustment 12, which addresses the South Point Energy Center purchase.

A. Adjustment 12 provides for increases in the South Point Energy Center purchased power contract capacity from 25 MW to 35 MW, with an accompanying increase in the capacity charge from $8.65/kW per month to $8.70. This change would increase expenses by $530,000. Liberty's review of this adjustment found it to be appropriate.

Q. Please discuss AEPCO's adjustment 7, which annualizes certain scheduling and trading service agreement costs.

Adjustment 7 annualizes revenues associated with scheduling and trading service agreements between AEPCO and other various parties. The net effect of this adjustment would be to increase revenues by $333,000. Liberty's review of this adjustment found it to be appropriate.

Q. What other expense adjustments has AEPCO claimed that Liberty reviewed?

A. AEPCO made a number of operational changes to reduce cost. Some other areas of expense required additional support and increased cost. For example, adjustment 8 reflects increased cost associated with an agreement negotiated with Aces Power Marketing ("APM"). This agreement transfers AEPCO's load schedule and trading services to APM, at a cost increase of $870,278. The transfer allowed AEPCO to reduce staffing and related cost, which its filing reflected in reduction to payroll costs. AEPCO adjustment 4 reduces payroll expenses associated with an overall reduction of enterprise staff levels from 302 to 261 employees. This reduction came as part of the Reduction in Force ("RIF") program. The overall reduction in AEPCO's share of this reduction (including the reductions associated with the transfer of work to APM) amounted to $2.3 million of expenses. Liberty reviewed the underlying cost adjustments, which included reductions in higher paid staff positions (due mainly to attrition) and some minor new additions of administrative staff. The changes primarily affect administrative staff; reductions in operating and maintenance staff are minimal. The 2011 per-book values included additional cost associated with the RIF program, to cover employees leaving the work force. These transition costs included one month's payment for each year of service (with a maximum of twelve months), payment of accrued managed time off, and one-half of accrued sick leave for employees over 55 years of age. No payment for sick leave went to departing employees under this age. These nonrecurring costs comprised a substantial amount of the payroll expenses AEPCO removed from the 2011 per-book values. Liberty verified that these costs were excluded from the pro forma expense claim. Liberty found AEPCO's adjustments to be appropriate.

Q. Explain AEPCO's maintenance outage overhaul adjustment number 6.

A. The adjustment can somewhat be characterized as an accounting / ratemaking adjustment under which AEPCO proposes a three-year amortization of minor outage expense (rather than a two-year period); and a six-year period for major outages. Liberty does not necessarily agree with the characterization of this adjustment as reflecting an amortization expense. Nevertheless, we find these periods consistent with sound ratemaking concepts and appropriate in duration, given fluctuations in such costs. We found AEPCO's $411,000 reduction in costs appropriate.

Our concern about terminology arises from the fact that it is suggestive of the creation of a regulatory asset, which is not what we view as AEPCO's intent. Creating such an asset establishes an expectation of full recovery of the same amount in subsequent rate proceedings. That should not be the case here.

Q. Please discuss AEPCO's adjustment 10, which concerns rate case expense.

A. Liberty takes the same position it does on adjustment 6, when it comes with regard to AEPCO's rate case expense claim number 10. This adjustment seeks a three-year amortization period for the estimated $240,000 ($80,000 per year) for outside professional assistance in this proceeding. We consider this claim more appropriately to be a normalization, rather than an amortization. Information provided in response to DK-1.68 indicates a cost slightly in excess of $54,000 (as of the date of that response) for such outside professional services. Liberty understands additional work and fees will be incurred as the case progresses. Thus, Liberty, recommends that the claim be based upon an updated cost value rather than an estimate, based upon more timely actual updated cost information, when available.

Q. What is Liberty's position with regard to AEPCO's adjustment number 9 related to the $764,000 proposed reduction in expenses to cost cutting programs?

A. Liberty reviewed AEPCO's supporting information related to this item, and we discussed the matter with AEPCO staff. The reduction relates substantially to 2012 items of nonrecurring expenditure, such as: $100,000 for DSC card repair, $80,000 for upgrade to units #2 and #3 software, $20,000 for service inspections, $31,000 for spare GT4 filters, and $358,000 of inspection and repair to units #2 & #3 circulating water. These items total $589,000. The remainder of the adjustment concerns reduced limestone supplies of $55,000, $100,000 in reduced temporary craftsman, and a $20,000 reduction to vegetation management. Our interviews with AEPCO staff indicated that the listed reductions will not affect ongoing operation and maintenance of the system facilities. Liberty found the adjustment appropriate.

Q. Please discuss the remaining expense adjustment items reflected in AEPCO's rate filing.

A. AEPCO's adjustment 11 removed California parties legal cost as a non-recurring item. The $1,212,332 costs removed were professional fees booked in 2011. The matter was resolved in March 2012. Liberty finds this adjustment appropriate, as we do adjustments 14 and 15, which reduced interest expense by $531,768 and $704,463, respectively. These reductions resulted from a Commission-approved refinancing arrangement and the need to annualize interest expense within the test year. Finally, adjustment 16 increases revenues to synchronize the PPFAC revenues with the pro forma fuel and purchase power energy costs made in the previous adjustments. This adjustment amounts to $285,000. We found it to be appropriate.

Q. What other analysis did Liberty undertake to determine the reasonableness of the pro forma adjusted 2011 test period?

A. Liberty requested and received additional information pertaining to 2009 and 2010 per-book cost. We compared that information to the 2011 per-book values. Our purpose was to identify any trends that would affect the reasonableness of the adjusted, normalized 2011 test year. Liberty also reviewed AEPCO's detailed general ledger accounting information for the 2011 test year. We then requested clarifications pertaining to various costs included in the test year in order to test them for reasonableness. During this review process Liberty determined that AEPCO did not effectively account for certain donations and certain advertising expense included in the filing. We do not consider such expenses to comprise a necessary cost of performing regulated service. For example, AEPCO booked $5,544 of donation expenses in 2011 and also received a refund of $30,918 from its National G&T Managers Association for prior years' activities. A credit value of $25,373 reflected in the claim should have been removed, an increase in the overall expense claim. However, Liberty's review of AEPCO's advertising expense claims found $34,315 of expenses not related to matters necessary for the conduct of regulatory service. These items included a golf tournament, FFA/4-H advertising, and other matters discussed fully with AEPCO staff. Thus, combining the $25,373 credit in the donations account and the $34,315 of non-allowable advertising expenses Liberty proposes a net downward adjustment of $8,942.

Finally, Liberty reviewed AEPCO's membership and dues fees of $426,844. We found that a portion of the fees paid to various groups to be appropriately includable, but others, such as lobbying and advocacy activities are generally considered unacceptable for ratemaking purposes. Liberty recommends the removal of a portion of the fees paid based upon the percentage identified by AEPCO in the prior proceeding. The next table lists the membership group, the fees paid, and the percentage to be removed. We recommend a downward adjustment of $88,538 in such fees.

Table 8 – Membership/Dues Adjustment Analysis			
Membership Group	$/Amount Paid	% Lob/ Adovc.	$/Amount Removed
Grand Canyon State Electric Cooperative Assoc., Inc.	$131,537	26%	$34,200
National Rural Electric Cooperative Association	59,743	24%	40,000
Consumers United for Rail Equity	50,000	80%	14,338
Total Downward Adjustment			$88,538

Q. Please summarize the overall revenue increase impact, rate of return, DSC, and TIER values based upon Liberty's recommendations.

A. As discussed above and summarized in the table 9 below, Liberty proposes downward adjustments to operating expenses of $8,942 for Advertising and $88,538 for Memberships and Dues expenses, which together would produce a net decrease of $97,480 to current pro forma expenses and current pro forma revenue requirements. As discussed in Mr. Vickroy's testimony, AEPCO's risk factors lead him to recommend no change to AEPCO's revenue level. He therefore disagreed with AEPCO's proposal to decrease revenues and target the debt service coverage ratio at 1.32 under proposed revenues. The same logic leads us to recommend that there be no reduction to reflect the $97,480 in Advertising and Memberships and Dues discussed immediately above. Given the magnitude of the issues addressed by Mr. Vickroy, this less than $100,000 is not material. Thus, pro forma current revenues would remain unchanged at this time under Liberty's recommendation as shown in Table 9 below.

AEPCO's filing provided an analysis that indicated a 3.99% overall rate of return value had it utilized the traditional rate base rate of return approach. As described earlier, Liberty proposed two rate base adjustments, a $3,389,294 increase to rate base related to an error in overstatement of accumulated reserves to depreciation expense based upon new depreciation rates. Again, the change in depreciation expenses does not affect net book values of assets at the end of the test year. Liberty also proposed a downward adjustment of $9,786,849 to fuel stock values due to changes in inventory value and overstatement of tonnage requirements for ratemaking purposes - thus, net rate base reduction of $6,388,555. As shown in Table 9 below, with no change to the income level under Liberty's proposal when divided by the adjusted or lower rate base value would produce a 5.82% overall rate of return value.

Table 9 – Summary Revenue Requirement Impact of Liberty's Recommended Adjustments					
	AECO Pro Forma Request As-Filed			Liberty Recommended	
	Current	Change	Proposed	Adjustments	Proposed
Gross Revenues	$163,624,600	($4,527,465)	$159,097,135	$4,527,465	$163,624,600
Oper. Expenses	$148,420,479	$0	$148,420,479	$0	$148,420,479
Operating Income	$15,204,121	($4,527,465)	$10,676,656	$4,527,465	$15,204,121
Rate Base	$267,463,587	$0	$267,463,587	($6,388,555)	$261,075,032
Rate of Return	5.68%		3.99%		5.82%
Operating Income	$15,204,121	($4,527,465)	$10,676,656	$4,527,465	$15,204,121
Int. & Other Ded.	($9,745,481)	$0	($9,745,481)	$0	($9,745,481)
Other Income	$1,026,046	$0	$1,026,046	$0	$1,026,046
Net Margin	$6,484,686	($4,527,465)	$1,957,221	$4,527,465	$ 6,484,686
Depr. & Amort.	$13,349,504	$0	$13,349,504	$0	$13,349,504
Int. On L/T Debt	$9,281,871	$0	$9,281,871	$0	$9,281,871
Available Funds	$29,116,061	($4,527,465)	$24,588,596	$4,527,465	$ 9,116,061
P&I on L/T Debt	$18,627,724		$18,627,724		$18,627,724
DSC	1.56		1.32		1.56

Q. Do you have any other comments with regard to the AEPCO filing?

A. Yes, we retain the ability to amend our recommendations following any changes that may come to light as a result of further discussions, including updated cost information, possible stipulated issues and other various revenue requirement elements that may have an impact on revenue requirements.

Q. Does that conclude your direct testimony?

A. Yes, it does.

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	DOCKET NO. E-01773A-12-0305

DIRECT

TESTIMONY

(ENGINEERING ANALYSIS)

OF

RICHARD MAZZINI

(CONSULTANT)

ON BEHALF OF THE STAFF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MAY 1, 2013

TABLE OF CONTENTS

EXHIBITS

Introduction

Q. Please state your name, occupation, and business address.

A. My name is Richard Mazzini. I am an Executive Consultant associated with The Liberty Consulting Group ("Liberty"). My Liberty business address is: The Liberty Consulting Group, 65 Main Street, P.O. Box 1237, Quentin, Pennsylvania 17083.

Q. Mr. Mazzini, briefly summarize your education background and professional qualifications as they relate to the subject of your testimony.

A. I have been engaged as a consultant and utility manager in the electric utility industry since 1967. Until 1995, I was employed by Pennsylvania Power & Light Company in a variety of senior management positions. After entering the consulting business in 1995, I served in senior positions with Washington International Energy Group, Navigant Consulting and ABB. I have been an independent consultant since 2001. As a consultant, I have assisted utilities throughout the United States, Canada, the Caribbean and Europe and have worked on behalf of many utility regulatory authorities.

I have a B.E.E. degree from Villanova University and an M.S. degree in Nuclear Engineering from Columbia University. I am a Registered Professional Engineer in Pennsylvania and a member of the Institute of Electrical and Electronics Engineers and the American Nuclear Society.

Q. Have you prepared a more detailed summary of your background?

A. Yes; Exhibit RAM-1 provides it.

Q. What is the purpose of your testimony?

A. Liberty conducted an engineering analysis of the generating assets of AEPCO. Our goal was to evaluate AEPCO's Apache Plant, including station performance, operations, maintenance, and capital improvements. We reviewed existing maintenance practices, examined how AEPCO documents them, and reviewed management controls to ensure proper implementation and execution of those practices. Liberty also reviewed plant outages, and conducted a review designed to determine the "used and useful" nature of rate-base assets. Liberty's review included a physical inspection of the Apache Plant and interviews with the personnel responsible for managing key functions at the plant. We also reviewed AEPCO's recent assessment of the remaining useful life of the assets.

This report presents the results of Liberty's review, categorized into the following subjects:

- Station performance
- Outages
- Maintenance
- Capital additions and rate base
- Facility review.

I directly performed the work reflected in the Engineering Analysis and Power Plant Operations task areas, prepared a report addressing the findings, conclusions, and recommendations of that examination, which is included as Exhibit RAM-2. The purpose of my testimony is to support and respond to questions regarding Exhibit RAM-2.

Q. Does that conclude your Direct testimony?

A. Yes, it does.

Richard Mazzini

Areas of Specialization

Management and regulatory audits; utility operations, including nuclear and other power production; power marketing and risk management; strategic planning; organization analysis and competitive re-structuring; project management; cost management; and tariff design and management.

Relevant Experience

The Liberty Consulting Group

Public Service Commission of New York – A management audit of Iberdrola SA/Iberdrola USA/NYSEG and RG&E. Assistant Project Manager for a 14-member Liberty consultant team.

Public Service Commission of New York – A management audit of Con Edison. Assistant Project Manager for a 13-member Liberty consultant team.

Iowa Utilities Board – Lead Consultant for the reviews of Electric Operations and Emergency Planning for Liberty's management and operations audit of Interstate Power and Light.

Arizona Corporation Commission - Consultant on Liberty's benchmarking analysis of Arizona Public Service. This study covered a ten-year audit period and benchmarked Arizona Public Service's performance with the following metrics: Operational Performance, Cost Performance, Financial Performance, Affiliate Expenses, and Hedging & Risk Management.

Maine Public Utilities Commission – Lead Consultant for the review and analysis of proposed new transmission project, the Maine Power Reliability Project (MPRP). Lead Consultant for economic analysis.

Public Service Commission of Maryland – Lead Consultant supervising the various auctions for procurement of power for Maryland's standard offer service (SOS) customers and support for the PSC in their analysis of new approaches to SOS supply.

Lead Consultant for Gas and Electric Infrastructure Improvement on Liberty's work for NorthWestern Energy to formulate long-range integrated infrastructure plans for its multi-state electric and natural gas distribution utilities. This project includes consideration of how to incorporate "Smart Grid" technology into infrastructure plans in a manner that will enable the Company to roll out new capabilities and services as technology makes them available, without undue acceleration of capital spending as uncertainties in this new marketplace become resolved.

Lead Consultant for Liberty's audit of Arizona Electric Power Cooperative for the Arizona State Corporation Commission which included reviews of fuel procurement and management, bulk electricity purchases and sales, power plant management, operations and maintenance, energy clause design and operation, and other issues affecting the prudence, reasonableness, and accuracy of costs that passing through the fuel and energy clause.

Lead Consultant for Liberty's audit of East Kentucky Power Cooperative, which included examinations of Governance, Planning, Finance, and Budgeting. Liberty performed for the Kentucky Public Service Commission an examination of governance at a generation and transmission cooperative serving 16 distribution cooperatives across the state. This study came in the wake of significant financial difficulties and also addressed planning, budgeting, financial, and risk functions and activities.

Lead Consultant for Liberty's audit for the Virginia State Corporation Staff of Potomac Edison Distribution System Transfer. Liberty examined the public interest questions associated with the transfer by an Allegheny Energy's utility operating subsidiary (Potomac Electric) of all of its electricity distribution operations business and facilities in Virginia to two rural electric cooperatives.

Management Audits

Public Service Commission of New York – An operational audit of Con Edison's reliability and emergency response planning and processes. Lead Consultant for corporate strategy and priorities, emergency planning and organization.

Federal Energy Regulatory Commission (FERC) – A review of the California ISO. Examined governance issues, operating procedures, transmission planning and analysis, organizational issues, interfaces with stakeholders and recommendations for the restructuring of the California market.

City of Seattle (Washington) – Review of the City's utility, commissioned by City Council and the Office of City Auditor, to analyze financial strategies, power market and risk management strategies and governance schemes. Lead Consultant for risk management.

St. Vincent Electricity Services, Ltd. – A management audit commissioned by the Board of Directors. Scope included generation, transmission, distribution, organizational assessment, safety, procurement and fuel.

New Jersey Bureau of Public Utilities – Evaluation of the gas supply and hedging programs of the four New Jersey gas distribution companies.

New York Power Authority – Consulting support for an internally sponsored audit of energy risk management functions.

Strategic Business Planning

Barbados Light & Power Company – Project Manager and Lead Consultant for a strategic planning initiative. Major areas of attention included new generation options, regulatory strategies, competitive threats, tariff design, new business opportunities, human resource issues, and planning processes.

Barbados Light & Power Company – Project Manager and Lead Consultant for the development of a model for the risk analysis of various new generation investments.

Electricité de France – Provided business planning and analysis services in the furtherance of the utility's wholesale and retail businesses. The work included research and analysis of potential gas partnerships, trading alliances and development of new retail markets throughout Europe.

SaskPower (Saskatchewan) – Project Manager and Lead Consultant for development of a strategic plan for the Power Production Business Unit. The project included asset valuation and optimization, transmission plans and strategies, efficiency improvement, market analysis and organizational options.

Omaha Public Power District – Project Manager and Lead Consultant for an extensive strategic business planning initiative. This multi-phase project spanned one year and included (1) asset evaluation, estimation of potential stranded costs and stranded cost mitigation strategies; (2) business growth strategies, including retail retention and expansion, new products and services, new utility businesses, wholesale marketing and bulk power trading; (3) corporate restructuring through the formation of four new business units; (4) organization design, including the creation of two new marketing organizations and a new trading floor; and (5) regulatory and legislative strategy development.

Omaha Public Power District – Project Manager and Lead Consultant for a follow-up analysis to the above project a year later to recommend added steps and course corrections. Provided new recommendations on organization design, customer service, stranded costs, energy marketing and trading initiatives, risk management, new business development, new products and services and strategic planning processes.

A Large Canadian Provincial Electric Utility – Strategic planning and business support in the analysis of future generation and transmission options associated with a major new generation construction project.

Tennessee Valley Public Power Association - Project Manager and Lead Consultant for development of a comprehensive new business strategy that reinvented the Association for a competitive environment. Key elements of the plan included a new expanded focus on government relations and the influencing of public policy, as well as the creation of four new business units and business endeavors.

City Council of Los Angeles (California) - Advice to the Council on the strategic plans of its municipal electric utility. Conduct of a workshop for the Council and staff on restructuring and competitive issues. Review of power marketing alliance strategies.

Riverside Public Utilities (California) - Analysis of the potential to sell all or part of the utility. Development of a new business vision and strategy. Analysis of outsourcing and alliance possibilities. Development of a power supply alliance, including design of the venture, development of RFP, evaluation of bidders, selection of finalist and negotiations. Organizational design and implementation. Planning and project management support for activities leading to open access.

Lower Colorado River Authority – Consulting support for strategic review and development of alliance strategies. Facilitation of management workshop to develop strategic responses to key issues and to examine options for strategic alliances.

ElectriCities of North Carolina – Business simulations and strategic planning for the North Carolina Power Agencies.

ElectriCities of North Carolina – Analysis of the Carolina P&L – Florida Progress merger with resulting strategies and negotiations on behalf of ElectriCities.

4–County Electric Cooperative - Strategic planning support for the Chief Executive Officer and Board of Directors. Designed and facilitated a planning workshop for the Board of Directors and key managers. Followed up with subsequent action plan for the Board.

Project and Cost Management

Omaha Public Power District (OPPD) – Lead Consultant responsible for design and implementation of a cost management program for a major overhaul of the Fort Calhoun Station. This $400 million project involved replacement of the two steam generators, pressurizer and reactor vessel head.

Power Marketing, Procurement and Risk Management

Public Service Commission of Maryland – Consultant supervising the various auctions for procurement of power for Maryland's standard offer service (SOS) customers and support for the PSC in their analysis of new approaches to SOS supply.

Electricité de France – Supporting services for the implementation of a large trading and marketing alliance in Europe, including reporting and control processes and training workshops for employees.

SaskPower - Project Manager and Lead Consultant for the expansion of the bulk power marketing program and creation of an energy trading floor. Work included extensive recommendations on corporate structure, organization, trading and marketing strategies, trading floor characteristics, management controls, risk management strategies, training, alliance building and external interfaces.

Public Service Commission of Maryland – Provided consulting support to the PSC in the approval of the settlement agreement relating to Standard Offer Service (SOS).

New Businesses

BGE Corporation (Constellation Nuclear Services) – Project Manager and Lead Consultant for the business analysis, planning, design and startup of a new subsidiary business for the client. The business, provision of nuclear related services to U.S. and international utilities, was successfully started in July 1999.

Electricité de France – Provided support in the planning, analysis, structure and negotiation of a large international energy trading and marketing alliance (EDF Trading, based in London).

Tennessee Valley Public Power Association – Project Manager and Lead Consultant for a survey and analysis of the Association's more than 150 member utilities. Produced an analysis with recommendations for the products and services that can best serve the members in a deregulated environment.

Municipal Electric Association (Ontario) – Project Manager and Lead Consultant for the development of a definitive business plan for a new power procurement business on behalf of the Association's more than 250 municipal electric utilities. Work included initial feasibility assessments followed by a complete actionable plan for the creation of the new organization, including structure, organization, staffing, financing, market analysis, contingency plans, product offerings and promotional strategies. The resulting new company became a reality in late 1997.

ENERconnect (Ontario) – Served as interim Vice President of Marketing and Customer Service for the startup of this new power procurement and services company. Project Manager and Lead Consultant for the development of a detailed operational plan for startup. Assisted in all aspects of startup including organizational design, business strategies, product design and development and support to executive management and the Board.

ABB Energy Solution Partners – Consulting support for ESP-sponsored projects, including customer and project research, project structure, energy supply options, alliances and preparation of proposals. Included regulatory research and discussions in Nevada, Michigan, New Jersey and New York.

Ambient Corporation – Consulting support for strategic and tactical business planning for this startup firm specializing in power line communications (PLC), including development of commercialization plan and supporting management processes, support of business plan, product and service development, regulatory strategies and financing documentation.

PacifiCorp - Customer research with two groups of large industrial and commercial customers. Designed and managed interactive workshops to obtain their input, served as subject matter expert for the sessions, produced and presented comprehensive analyses of the results with strategic insights for the client's marketing initiatives.

T&D Support

Alberta Electric System Operator – Analysis of transmission loss methodologies for the Alberta market.

A Large Canadian Provincial Electric Utility - Business planning support for the transmission business unit. Analysis of the business potential of new transmission opportunities. Analysis of U.S. transmission policies and their potential impact on a Canadian player in the U.S. markets.

Utility Management

Pennsylvania Power & Light Company - Served in a variety of management positions in a long career with the utility. Responsible for strategic business planning, rates, bulk power marketing, system operation, management of non-utility generation contracts, rate design, market research and contract negotiations with large customers. Key management roles in cost management, planning and scheduling for all Susquehanna nuclear station design, licensing, and startup activities including outage management.

Other Consulting Positions

Senior Vice President for ABB Energy Consulting, responsible for managing consulting engagements for a variety of U.S. and European energy firms.

Principal for Navigant Consulting, Inc., involved in numerous consulting engagements serving the electric utility industry in competitive initiatives.

Senior Vice President for the Washington International Energy Group, responsible for the firm's competitive positioning practice.

Education

M.S., Nuclear Engineering, Columbia University
B.E.E., cum laude, Villanova University

Registrations

Registered Professional Engineer – Pennsylvania

Memberships

Institute of Electrical and Electronics Engineers, American Nuclear Society

Final Report
Review of AEPCO
Engineering Analysis and
Power Plant Operations

Presented to the:

Arizona Corporation Commission

By:

THE LIBERTY CONSULTING GROUP

65 Main Street
Quentin, Pennsylvania 17083

(717) 270-4500 (voice)
(717) 270-0555 (facsimile)
Admin@LibertyConsultingGroup.com (e-mail)

May 1, 2013

Table of Contents

I. Engineering Analysis and Power Plant Operations

Liberty conducted an engineering analysis of the generating assets of Arizona Electric Power Cooperative, Inc. ("AEPCO"). Our goal was to evaluate AEPCO's Apache Plant, including station performance, operations, maintenance, and capital improvements. We reviewed existing maintenance practices, examined how AEPCO documents them, and reviewed management controls to ensure proper implementation and execution of those practices. Liberty also reviewed plant outages, and conducted a review designed to determine the "used and useful" nature of rate-base assets. Liberty's review included a physical inspection of the Apache Plant and interviews with the personnel responsible for managing key functions at the plant. We also reviewed AEPCO's recent assessment of the remaining useful life of the assets.

This report presents the results of Liberty's review, categorized into the following subjects:

- Station performance
- Outages
- Maintenance
- Capital additions and rate base
- Facility review.

As in our prior evaluation, Liberty has found Apache's technical performance, its people, and its facilities to be generally sound. The management team was knowledgeable, engaged, open, and supportive of Liberty's evaluation. The organization appeared to have expertise and tools commensurate with the needs and challenges that the station faces.

With respect to factors relevant to this rate filing, Liberty's engineering analysis comprises two parts: (a) the effectiveness of plant management, including operations and maintenance of the units, and (b) AEPCO's strategy for the station and the implications for recent and future investments, as well as its ability to economically meet the needs of its members.

With respect to the effectiveness of plant management, we believe that Apache's power plant operations are generally appropriate and typical of the industry. Maintenance practices and spending appear to be efficient and consistent with the station's needs and good utility practice. The station is well-maintained.

From a strategic perspective, however, the warning signals identified in the previous rate case in 2010 have grown into firm indicators of problems that leave the future of Apache uncertain. The recent EPA challenges add to this burden, but it remains very clear that the strategic issues forcing the station's decline existed before the EPA's actions and will remain afterwards as well. AEPCO needs to consider all these factors in its assessment of Apache's future.

A realistic assessment of Apache's future would better enable AEPCO, the members and the ACC to protect customers. The questionable future of the station, with or without the EPA uncertainties, raises the prospect of stranded investment for members. The sooner they address the possibilities the better they will be able to mitigate the effects on their customers.

1. Station Performance

The results of our analysis generally support the rate filing from technical and operating perspectives. Other factors, however, serve to drive station performance down and to threaten Apache's future. ST2 and 3 produce nearly all of the station's output and that output has declined drastically in recent years. Economic factors have primarily driven this reduction in output. Reduced output, however, worsens the units' economics, which further worsens output – causing a spiral whose end is not in site.

Meanwhile, ST1 has remained idle for an extended period. The unit operated at negligible levels in 2011, and not at all in 2012.

2. Outages

Liberty's review of outages at ST2 and 3 found no major concerns. There were only two major planned outages reported. Forced outages, although increased, were not an item of significant concern. Our prior evaluation cited an inordinate number of personnel errors as causes for unit outages. The rate of such trips at Apache is far above the industry-reported levels. This level of performance remained unchanged since our last evaluation, despite improvement initiatives reported by AEPCO.

3. Operations and Maintenance

Liberty's review of maintenance policies and practices at Apache found no fault with them. The detailed systems used to plan, monitor and execute work orders are effective. Nevertheless, summary level information, of the type one would expect for management to provide program oversight, does not appear to provide the perspectives that managers usually require.

Spending on maintenance has generally been consistent for many years. Recent reductions resulted from efficiency measures. We found no indications that maintenance spending has been insufficient.

4. Capital Additions

Effective capital planning will be enhanced through the development of a realistic plan going forward, including the operating role of the units and their remaining lives. Current operating assumptions and the remaining life study are unsuitable for future decision-making. Recent investments in ST1, which has not returned to a used and useful state following them, represent a valuable example of what can go wrong in such an environment.

In the immediate case of ST1, new investments were made in 2010. The unit has since played little or no role of value. There is not a basis to find that those 2010 investments represent used and useful assets. In fact, ST1 as a whole appears to lack usefulness at this point.

5. Summary of Recommended Actions

Our recommendations take into account AEPCO's response to the previous rate case Decision. Accordingly, we emphasize a single recommendation that merits consideration by this Commission, and equally by the AEPCO Board and the members. Specifically:

- A comprehensive study of the future of Apache should be completed within the next six months. The study should feature:
  - Comprehensive operating scenarios based on the economics of the station.
  - Assessment of remaining life based on economics, physical condition and planned operating mode.
  - A starting assumption that the EPA issues will not affect the station.
    - The results can then be used to assist in developing EPA strategies for dealing with the EPA issue.
    - A second phase of the study, when EPA impacts are clearer, can be conducted if appropriate.
  - Consideration of independent third party oversight to assure that assumptions, methods, and conclusions are reliable.
  - Rate analyses to determine what, if any, stranded costs will be borne by the members and their customers.

[illegible]

The Arizona Electric Power Cooperative ("AEPCO") was founded in 1961. Through a major restructuring in 2001, AEPCO was organized into three entities:

- AEPCO, as a power supply organization
- SWTC as the transmission entity for serving the needs of member cooperatives
- Sierra Southwest Cooperative Services ("Sierra"), which provides services and personnel for both AEPCO and SWTC.

In 2011, the COO positions over each of the three organizations were eliminated, and a new team of ten division managers was appointed. This team has responsibility for each of the primary operational functions. AEPCO indicates that this new structure and its implementing initiatives have "yielded a better alignment of resources with core functions by outsourcing certain services, reducing or reassigning staff, and improving processes and communications." This new approach seems to be functioning well as it applies to Apache.

The Apache station comprises AEPCO's sole physical generating asset. It consists of the following units:

- **Steam Units 2 and 3**: Two coal fired units of 175 MW each that now produce virtually all of the energy output of the station. The units historically served as base load generation, but transitioned to load following service in the last five years, due to economics. The units are relatively young (34 years old) for coal units of this size. The typical unit age in the industry lies in the range of 50 years.
- **Steam Unit 1**: A gas fired unit that is positioned to operate in a combined cycle mode with **Gas Turbine 1** for a total output of 85 MW. The unit has been off line for an extended period, due to economics.

- **Gas Turbines 2, 3 and 4**: Peaking units having a combined capacity of 129 MW. GT4 produces a minimal amount of energy; GT2 and 3 have a near-zero capacity factor of late.

The Environmental Protection Agency (EPA) has recently taken actions against Apache and other selected regional coal units on the basis of haze. A literal response to EPA demands would require new equipment that is simply impractical, given this station's economics. The notion of new environmental requirements being the fatal bullet for already economically weak coal units is not new. The country is experiencing an ever-increasing number of retirements. Quite literally, the survival of Apache is at stake. Failure to come to a workable arrangement with the EPA could have major consequences, including potential closure of the plant by 2017. AEPCO is developing strategies for how to avoid that eventuality.

C. Station Performance

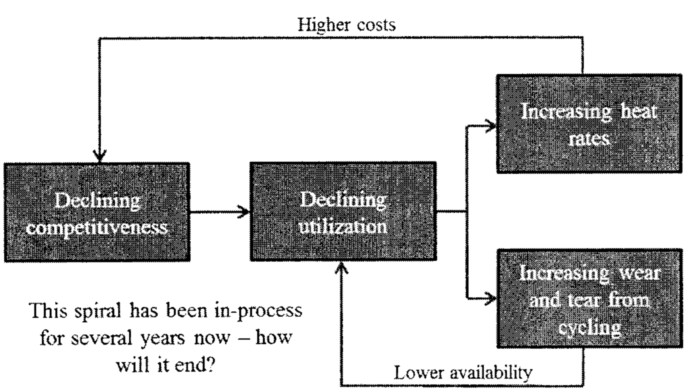
Liberty's last evaluation of Apache in 2010 made clear that we felt that the contributing role of the station was in decline. Net output dropped 39 percent between 2000 and 2009. Much of this decline occurred in the last two years of the period, with an especially precipitous decline in 2009. Management believed that the decline was an anomaly. Liberty described "indications that more troubling forces are at work." The next three years proved that assessment to be accurate, as the accompanying table illustrates.

Annual Net Output (GWh)

	ST2 and 3	All Other Units	Total Station
2000	2,869	590	3,459
2009	2,008	91	2,099
2012	1,592	15	1,607

Our earlier assessment attributed the decline in station output primarily to economics and availability. High Apache coal costs had combined with low gas prices to make the units less competitive, while numerous outages lowered available time. Interestingly, the economic factors have changed for the better in the last three years:

- New coal contracts provided lower coal costs
- Natural gas prices in the region increased



Yet, the station's role has continued to decline at a rapid rate. Output is now less than half of 2000 levels and energy from the peaking units has fallen to near zero.

The problems faced by Apache are by no means unique. Coal units across North America have come under serious threat from varying combinations of escalated environmental requirements, subsidized renewables with must-run status (hence displacing base load units in some cases), and low gas prices. Plants that can no longer compete suffer reduced utilization and increased cycling. That combination degrades heat rate and availability, which then furthers the rate of decline. As a result, many coal plants are being retired and still more have had their expected lives reduced. We have observed that once the future holds early retirement, the end often comes quicker than expected, as generators can no longer justify sustaining capital investments.

As it is in very many small coal units across North America, lower plant utilization has produced less efficient operations, lower availability, and higher costs, all of which lead logically to even less utilization. AEPCO has not been successful in planning a responsive course. Three examples support this observation.

First, the prior rate case Decision ordered AEPCO to conduct a study of the future role of the Apache Station and how that role relates to member needs for future power supply. AEPCO submitted its study in October 2012. The study failed to address key fundamental questions. The results of the study should have provided guidance for future decision-making, such as power procurement strategies and appropriateness of future investments.

Second, on August 22, 2012, AEPCO submitted an Integrated Resource Plan that failed to acknowledge, or even discuss, the deteriorating role and questionable future of Apache.

Third, in May 2011, AEPCO's contractor issued a report purporting to assess "the probability of continued operation of these units to their planned end of life." That assessment failed to consider any economic factors that might shorten the life of the units. Yet the report's conclusions are predicated on increased capital investments which, of course, are being precluded by the station's economics. This simple fact should not be overlooked byAEPCO.

AEPCO has thus so far avoided this pivotal issue, whose eventual impact on the members therefore remains unknown. More recently, the problems posed by the EPA have taken center stage, and have served as a reason for avoiding the economic discussion. However, the impact of any EPA decision can only worsen the economic situation. Further, the failure to develop and use an accurate picture of the station's economics makes it impossible to define an optimum strategy for EPA negotiations, the appropriateness of environmental capital spending and, if necessary, subsequent litigation.

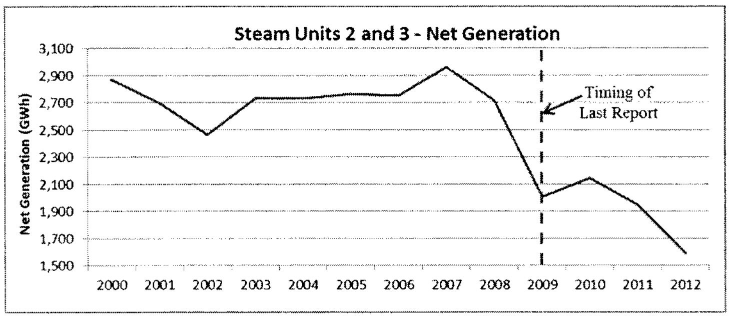
The economic analysis was inadequate to address effectively the concept of "used and useful" as it applies to AEPCO's ST2 and ST3 generating units. The appropriateness of capital investments is a function of remaining life, and we currently do not know whether that remaining life is more than 22 years (as currently claimed by AEPCO and its contractor) or just a few years, to be ended by economics, the EPA, or a combination of the two. AEPCO has curtailed capital spending in light of this uncertainty. That strategy will continue to be appropriate until some better definition of the future exists. Nevertheless, members remain in the dark as to the eventual impact on them from the obvious and well-established trends that are in place at Apache.

1. Steam Units 2 and 3

It is important to consider and emphasize the deteriorating operating contributions of the steam units. The units themselves represent something of a contradiction. On the one hand, Apache staff has done a good job with the resources they have. They maintain the station well and the staff operates efficiently. The actual and planned cost reductions do not appear to be starving the units, as sometimes happens in such economic situations. Instead, these reductions seem to originate in real efficiency improvements. This is a credit to the plant team, and would, under different economic circumstances, support a long remaining life.

However, circumstances are far from ordinary, and the strengths of the plant management cannot become the deciding factor. At work are external forces for which AEPCO management can only mitigate the impact, but not change the fundamental direction. If there were doubts about this in 2010, and AEPCO expressed those doubts as recently as 2012, the subsequent three years of data contradict them. Those three years extend the previous trend of lower output, higher heat rates and lower availability.

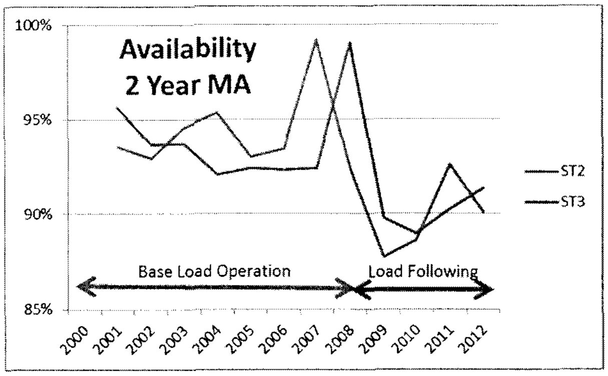
Consider the decline in unit output for the two previously base-loaded units. Note that the abrupt decline in 2009, which was due to availability issues, was somewhat dismissed by AEPCO as an anomaly. The updated chart suggests 2009 was indeed a one year anomaly, but that is within a rapidly declining five-year trend that clearly is not an anomaly.



Liberty's prior report updated by RM-1.118

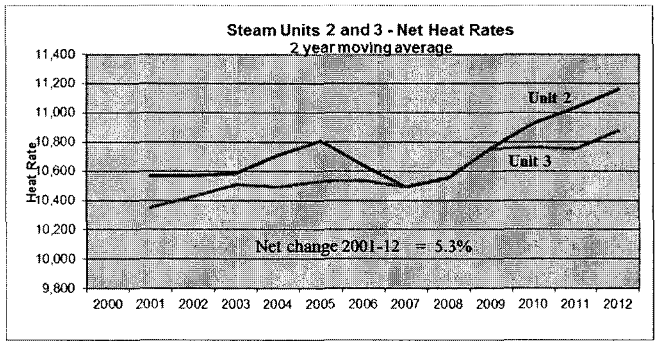
Liberty raised the concern that the shift to load following operation as opposed to base loading can have a substantial negative impact on plant equipment. The resulting cycling of the units creates added stresses and wear and tear that can lead to lower availability. Different equipment can be impacted in varying ways, but experience has been that boiler tubes and mills are particularly susceptible.

AEPCO's October 2012 response to Liberty's 2010 report dismissed this possibility, stating that "*AEPCO has evaluated [ST2 and 3] operation during 2009-11 and sees no indication that reduced station output has impacted the availability of these units or led to significant deterioration of plant equipment.*" This position was softened in 2013 interviews with the acknowledgement that cyclical operation does indeed negatively affect equipment.



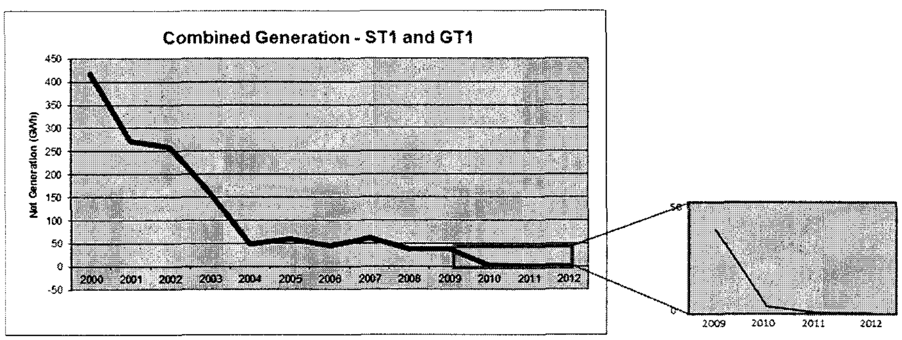
To the extent Liberty's hypothesis is correct, we would expect a gradual and continuing decline in availability starting after the first low capacity factor year (2009). And that is what the data in the accompanying chart shows. Note that deletion of the "anomalous" 2009 data does not change the trend. We would expect this declining trend to continue, and perhaps accelerate, as operation becomes more cyclical, with the likelihood that the units converge towards the lower availability levels that are typical of similar units in the industry.

AEPCO observes correctly that Apache availability exceeds that of similar units in the industry. However, this is not relevant to the concern, which deals with a forecasted further decline in the units' competitiveness.



The final element of the spiral, heat rate, has also trended as expected. Again, note the clear rise in heat rate that started with low capacity factor operations in the 2007-2008 timeframe. This is an inevitable consequence of part load operations. The plants are designed for optimum performance at rated load, and lower load means lower efficiency. Heat rate changes have a directly proportional impact on fuel costs. The approximately 5 percent increase in heat rates in 2012 represents a large economic impact on already economically challenged units.

2. Steam Unit 1 and Gas Turbine 1



RM-1.118

The role of these units, operating in a combined cycle mode and also referred to as CC1, has evolved considerably. Capacity factor was 60 percent in 2000, but then declined to the mid-single digits by 2004. Following the 2010 overhaul, the unit has had virtually no output.

One needs to consider how a presumably viable combined cycle unit in which a large investment was made in 2010 suddenly stops operating. The unit's value becomes questionable when it sits idle indefinitely, as it effectively has for more than two years. This circumstance makes it difficult to justify the costs associated with this unit, including the new amounts now proposed to be added to rate base in this rate case. When Liberty first raised these issues, AEPCO responded that the unit had real and tangible value as capacity. Liberty found such explanations questionable and repeated its concerns. AEPCO reiterated the "value as capacity" response. In March 2013, however, AEPCO reversed this position in response to our request for a formal explanation of how the unit, given its operating state at present and for the past two years, could have value as "capacity." AEPCO reported that "the unit does not qualify as non-spinning capacity when it is off line because it does not have 10 minute starting time." Instead AEPCO now takes the position that value lies in the ability to run the unit when market prices are high, stating that, "If market prices increase above the unit cost, AEPCO simply starts the unit to avoid the higher cost."

This value also appears illusory if such a condition has only existed 0.2 percent of the time in 2011 and never in 2012. Such negligible use of the unit to displace higher costs also lies at odds with any justification of the 2010 multi-million dollar investment. With the data now available, it is not possible to consider that new investment as used and useful, nor is it possible to any longer consider a unit that sits idle as used and useful.

In retrospect, the economics of this unit did not justify the new investment. Further, the failure to understand regulations that would limit the unit's operations after such an investment comprises a second failing in this decision. Those regulations now limit the unit to 35 full power days per year, or a capacity factor of less than 10 percent. In one sense, this limitation is moot; economics precludes any significant operation. In another sense, consideration of this limit at the time may well have prevented the decision to invest more in ST1 in the first place.

a. Treatment of Not-Useful Assets

Our conclusion that ST1 can no longer be considered used and useful begs the question of what should be the impact of this conclusion in the rate case. We respond to this question with a common sense consideration. Note that we do not presume to offer any conclusions on regulatory law in this engineering analysis and caution that such legal considerations could trump our recommendation.

In the case of an Investor Owned Utility ("IOU") with assets found to not be useful, the shareholders may be required to absorb any remaining costs associated with those assets, including their remaining book value, which would be "stranded." Simply stated, the shareowners, and not necessarily customers, would be available to absorb the cost if so decided by the regulator.

However, with respect to a cooperative utility, there is no third party to absorb the costs. The owners and the customers are the same. Customers therefore absorb the cost, either through higher rates or through stranded cost and reduced equity in the cooperative. Theoretically, the regulator could be somewhat indifferent to the used and useful rate treatment in that the member-customers are going to pay for the deficient asset one way or the other.

Thus, the issue becomes what action is appropriate for the ACC in this rate case. Liberty recommends a three-part approach.

First, as explained in our engineering analysis of Apache, AEPCO continues to manage the plant without a credible long-term vision or plan and such a failing precludes sound economic decisions. One result has been an unrecovered wasted 2010 investment in ST1. Under-informed decisions regarding the other units present a real and present risk. It is therefore essential that the plan and accompanying economic analysis recommended in 2010, and reiterated in stronger terms in our current engineering analysis, be immediately performed. AEPCO's Board, its customers and this Commission do not have critically necessary information in the absence of such a plan.

We emphasize that pending issues with the EPA offer no reason to delay this evaluation. In fact, the evaluation is a necessary precondition for defining an EPA strategy and, depending on the results of the evaluation, could possibly even render an EPA decision moot.

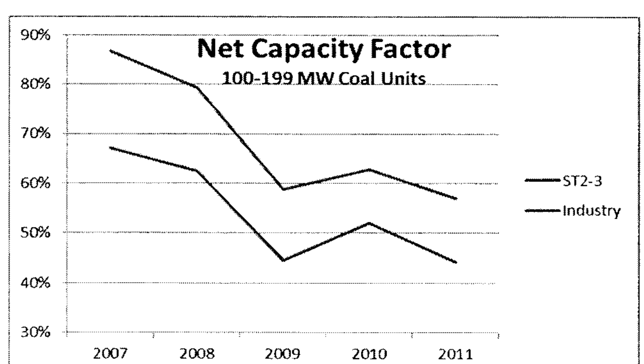
Second, while the plan is being prepared, we recommend an interim "no regrets" strategy. This approach means taking no actions that could worsen the potential for eventual stranded costs. No rate reductions of any kind should be considered at this time, whether from ST1 disallowances, income from successful litigation, or any other factor. If and when the stranded cost prospects are eliminated, rates could then be adjusted downward if appropriate.

Third, while the Commission has some means to influence AEPCO decisions and operations, governance is clearly in the hands of the member-customers, through their representatives on the AEPCO Board. It is here that accountability must lie. The Board's willingness to govern without a credible plan is problematic, and its own member-customers bear substantial risks as a result. It is important to engage the AEPCO Board in the process, in order to facilitate the protection of the end use customers.

3. Gas Turbines 2, 3 and 4

These three gas turbines function as peaking units. Units 2 and 3 have operated for the last several years with capacity factors of less than 1 percent. Unit 4 has operated at about 4 percent. Availability of all of the units has generally been in the high 90 percent range over the last few years. There are no real issues of performance at this time.

4. Industry Comparisons and Trends



In comparing the Apache units to the rest of the industry, the deteriorating state of coal units, especially smaller ones, becomes apparent. As suggested earlier, the declining utilization of such units is an industry-wide phenomenon, driven by lower gas prices, environmental policies, and displacement by must-run renewables. The problems at Apache in this regard are by no means unique, as shown by the accompanying capacity factor chart. It should be no surprise that the smaller, less efficient units have suffered the most, but larger coal units have also declined, although not to the same extent.

Our prior report compared Apache's performance to the industry and Apache fared well, both in terms of long term availability and output. This overall observation has not changed, but an industry comparison is nonetheless valuable at this time to help assess the future direction of small coal units, including Apache. In such comparisons, Apache may have already lost its primary advantage – that of a base load unit. Note that the typical industry unit of this size has been an intermediate unit for some time. ST2 and 3 have now joined that group.

The other advantage for Apache has been its age, which is much younger than the typical unit of this size. ST2 and 3 are 34 years old compared to the industry average of about 55 years. The notion of better performance is therefore not a surprise, nor is the proportionately declining performance. We note in this regard that the industry fleet is aging at a rate of more than 1 year per year which suggests that the retiring units have, like Apache, tended to be below the average age. Also, the number of units dropping from the population has accelerated, with 17 units retiring in 2011 from a population of 231.

In summary, one can conclude from the data that the future for any coal unit is threatened, and the threat to smaller, higher cost units is the most compelling.

D. Outages

1. Planned Outages

AEPCO provided cost and schedule data on only two planned outages in the 2010-11 timeframe. Both outages overran the planned duration, by 9 and 6 days respectively. Cost performance was under budget in total.

With only two data points and limited deviations, it is not appropriate to raise a concern. In our prior report, the analysis was more critical and we did recommend an improvement in outage planning and management:

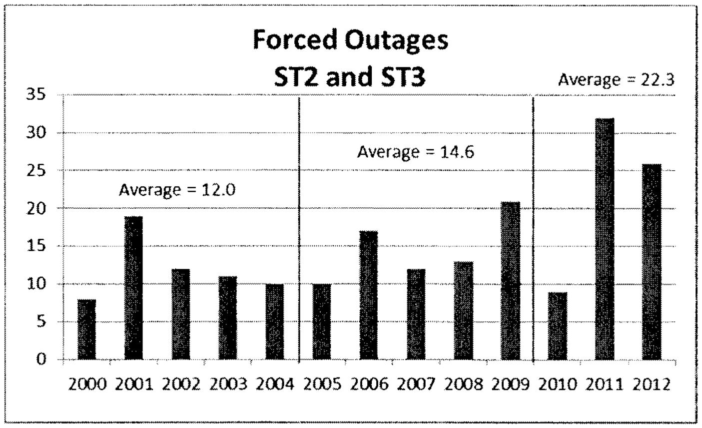
> *Management should consider providing more structure and formality, to a degree consistent with Apache's needs, for the outage planning and management efforts.*

Management responded that "summary outage plans, as recommended, will be prepared five to six months prior to an outage." We did not see any such reports and none were provided in response to an associated document request.

We continue to believe as we observed previously that an elaborate approach to outage planning and management is not likely to be cost effective at Apache. Further, management indicates that the systems and processes in use appear to be meeting their needs. We nevertheless do observe that, in our experience, summary data on plans and performance in outages represent the primary, if not only, method for senior management to understand outage performance. Quantitative presentations of schedules, including critical path, budgets, resource requirements, shift strategies, quantities of work, and deviations from expectations are traditionally in wide use elsewhere.

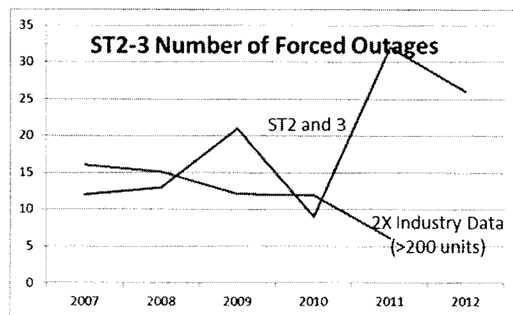
2. Forced Outages and Reductions of Output

We limit our discussion of forced outages to ST2 and 3. Outages are not an issue at the idle Unit 1. Forced loss of generation is tracked in the data by forced outages and by de-ratings, in which an event requires the plant to run at reduced output while the event is corrected. Where de-rates are considered, an equivalent outage duration is generally used; it corresponds to the fraction of capacity lost. For example, if the unit is forced to run at 50 percent of capacity for ten hours, the equivalent duration is 5 hours.

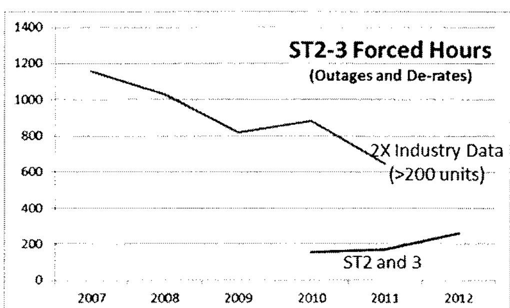


RM 1.119

Our last review cautioned that a trend of an increasing number of forced outages was becoming apparent. This trend was illustrated by comparing two five-year periods: 2000-2004 and 2005-2009. We are now able to add a new three-year period, 2010-2012. As the chart shows, the trend suspected last time is clearly a reality this time.



A major difference in today's analysis is the comparison to similar units. Our prior analysis concluded that despite the poor trend, ST2 and 3 were still superior to their peers. However, as the accompanying chart indicates, this is no longer the case. The industry has improved, while Apache forced outages have increased, with the results now showing for ST2 and 3 a greater number of forced outages than similar units have experienced.



We caution that this fact can be misleading. There is not much impact from the larger number of outages, because of their typically minimum duration. The total forced hours, including de-rates, have not deteriorated along with the frequency of outages; in fact, Apache is well below industry levels for forced hours.

3. Outage Causes

Liberty previously conducted a detailed analysis of outage causes for the three steam units in 2008 and 2009. Liberty also examined the outage data back to 2000 to identify any broad trends. We summarized the large number of outage codes into 17 summary codes that present a simpler and more effective characterization of unit issues.

We have updated this analysis for the three most recent years (2010-12), and have excluded Unit 1. A number of points of interest show in this data:

Number of Outages and De-rates		
	2008-09	2010-12
Boiler fuel supply	25.5	36.7
Boiler piping systems		
Boiler internals and structures		
Slag and ash removal		
Boiler tube leaks	3.0	1.0
Other boiler	13.5	17.7
Condenser	14.0	4.0
Circ Water	1.5	0.3
Condensate		
Feedwater	5.5	11.3
Other balance of plant	0.5	2.7
Turbine	4.5	3.3
Generator	1.0	1.0
Pollution control	0.5	0.7
External	1.5	4.0
Regulatory		
Personnel errors	9.5	9.3

RM-1.119

- Boiler tube leaks have been minimal and far less than generally experienced in such units. This is an excellent indicator and is contrary to our expectation of tube problems from added cycling of the boilers.
- In our prior review, condenser problems on Unit 2 had caused numerous de-rates. This problem has been effectively mitigated.
- The fuel supply category represents the major drop in performance over the last three years, and features primarily mill issues. The extent to which unit cycling has contributed to this is not clear; nevertheless, we would suspect that is a factor. We note that the number of events is generally consistent with similar units in the industry; therefore, these elevated levels cannot necessarily be considered out of line, especially for small load following units.
- Personnel errors remain unusually high. AEPCO's contention that perhaps other generators do not always report such errors may have some legitimacy. On the other hand, AEPCO's failure to show any improvement from the actions initiated since 2009 is problematic.

4. Replacement Costs

The issue of replacement becomes important when a utility experiences a large number or length of outages, as Apache did in our prior review. This was not the case in this review. Limited outage durations coupled with lower replacement costs due to the weak economics of Apache prevented replacement costs from becoming a concern at this time. AEPCO reported that they did not perform such calculations of replacement costs.

E. Operating and Maintenance

Liberty's review of the Apache maintenance program sought to answer the following basic questions:

- Is an effective maintenance philosophy and strategy in place?
- Are Apache's maintenance practices managed effectively?
- Does the maintenance program adequately balance cost and reliability?

One generally expects well-managed maintenance programs to be clearly defined and documented in terms of objectives, priorities, and strategies intended to reach those goals. Such formalities are essential in large, complex organizations, but can be considerably less important in smaller operations, where personnel tend to be tied together more closely and knowledge of the power plant is very high among the team. The latter characterization applies to the Apache Station, allowing its management and staff to be effective without a great deal of formality.

Liberty found now, as it did before, that an effective maintenance philosophy and strategy exists at Apache. We reached this conclusion based on interviews, consideration of the SAP maintenance management system, responses to relevant data requests, and observations at the plant. We consider clearly articulated policies and strategies preferable, and believe there is a real benefit to them, regardless of unit size. Nevertheless, we found no reason to believe Apache's programs are lacking.

1. Maintenance Programs and Systems

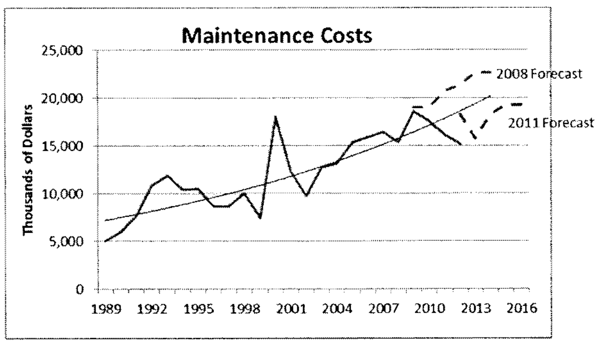
Two senior planners plan maintenance activities. In addition to corrective maintenance activities, Apache's preventative maintenance program covers about 60 percent of maintenance work orders.

The station's reliability centered maintenance program is staffed with two technicians and an administrative assistant. The program addresses scheduled equipment condition monitoring, including lubricant analysis, vibration analysis and infrared imaging, to predict equipment failure and plan maintenance intervention.

The SAP system appears to be a strong tool that supports the station on multiple fronts. This includes the overall maintenance management system including work orders, materials management, equipment histories and cost data. Liberty previously examined numerous sample reports, and found them all to be highly detailed and extensive.

2. Costs

The trend of maintenance costs at Apache has been contained and logical. Spikes have occurred occasionally, with the most recent associated with the 2009 problems. Costs appear to have been well-managed for a long time. We look for prolonged under-spending in maintenance and its inevitable consequences; however, there are no such indications at Apache. Specifically, we observed no indications that maintenance has been inadequate, either in our 2010 or 2013 inspections.



From our prior study, updated by RM-1.122

The current forecast is about 10 percent lower than the prior forecast and about the same amount below the trend line, which in itself is orderly and contained. Liberty discussed these reductions with management and the plans and results so far are positive. Specifically, savings appear to be generated more from prior investments in efficiency than the cutting of necessary work.

Effective cost management is increasingly a necessary factor in Apache's future, as O&M costs per unit of generation must inevitably rise as output declines. The initiatives underway so far have been effective, and there is cause for optimism.

F. Capital Additions

With age, investment needs grow, raising inevitable questions about a unit's future. Recent production trends at Apache make this question particularly critical. Liberty previously concurred with AEPCO's new investments at Apache, but emphasized that "it is critical to define the station's future mission as it will likely become increasingly difficult to judge the cost-effectiveness of station improvements." Three years later, the station's future mission has not been defined and it is indeed now difficult, or impossible in some cases, to judge the appropriateness of new investments.

1. Recent Investments

Liberty reviewed the major capital projects (estimated at >$500,000 each) placed in service since 2010. This sample includes 15 projects with an eventual installed cost of $29.3 million. With the exception of the 2010 ST1 furnace upgrade, all projects were associated with Units 2 and 3.

The process for the identification, justification, and approval of projects is well-established at AEPCO and other generating cooperatives. The content of the justifications is somewhat minimal but the analyses are presented well, with all of the relevant information contained at a reasonable summary level and in an easy-to-understand construction. The analysis sheets provide ample information for the initial consideration of management and the board with one key exception. As we have already discussed, there is no valid context within which to consider the capital proposals. This becomes apparent when one considers two critical, but seriously flawed assumptions that underlie the capital proposals: projected capacity factors and forecasted remaining useful life.

Projects >$500K - 2010-2012
(Thousands of Dollars)

		Budget	Actual
ST1	Furnace tube upgrade	3,900	2,967
ST1/2	Controls upgrade	350	822
ST2	Boiler cleaning upgrades	2,350	1,437
ST2	Stack liner coating upgrade	1,200	957
ST2	Converging tee duct replacement	1,075	895
ST2	Classifier replacement	1,105	835
ST2	SDAS tower out duct / damper upgrade	1,685	1,866
ST2	Stack liner and corrosion protection	4,580	3,954
ST2	Turbine control system upgrade	937	852
ST2/3	Main CW valve and EJ	1,190	746
ST2/3	Limestone mill addition	7,350	7,434
ST3	SDAS tower outlet dampers / ductwork upgrade	1,755	1,381
ST3	Stack breeching duct corrosion protection upgrade	812	643
ST3	Stack liner and corrosion protection	4,622	3,734
ST3	Turbine controls upgrade	850	813
	Totals	**33,761**	**29,336**

RM-1.123

a. Projected capacity factors

AEPCO has stated that, "With the termination of a certain 100 MW sale and the economic slowdown, Units 2 and 3 are projected to operate at approximately 70 percent capacity factors." This fundamental assumption, which is a part of the 2012-14 Construction Work Plan, is not helpful in a number of ways. First, it fails to recognize the primary cause of capacity factor reductions; *i.e.*, station economics. Second, by attributing the decline to the nation's economy, it suggests that the problems are temporary. Third, the 70 percent projection has already been proven to be too high, with neither unit reaching even 60 percent in 2011 or 2012. To the extent that future capital investments are justified with an assumption of a 70 percent capacity factor, such justification is invalid.

b. Remaining useful life

In our evaluation of "useful life" studies, including our last review of such a study at AEPCO, we are often critical, not necessarily of the results but surely of the methods. Such studies often carry so many qualifications as to render them useless. The current AEPCO study exhibits this tendency, and compounds it with numerous problematic assumptions.

The current study, "Affirmation of Unit Life and Net Salvage Value Study," was prepared in May 2011 by an outside firm. The firm took its assignment to be "to provide a high level assessment of the probability of continued operation of these units to their planned end of life." With respect to ST2 and 3, the outside firm concluded, in part:

> *It is anticipated the ST2 and ST3 can continue operation until 2035 provided AEPCO continues to maintain good operations, maintenance and safety practices, and to expand the capital required for periodic replacement/refurbishment of the equipment.*

So an indeterminate amount, in the form of unspecified replacement of equipment, is required in order to facilitate operation through 2035. This of course implies that expanded capital spending, even with limited remaining unit life, is always appropriate. AEPCO seems to support such a notion in its 2012-14 Construction Work Plan (Page II-13):

> *AEPCO recognizes that ST2 and ST3 are well into their expected lives and will require increasing expenditures for maintenance and capital improvements in order to maintain their place in a competitive environment.*

However, it is now apparent that such a commitment to increased spending is not appropriate, and that conclusion is reflected in AEPCO's proposed reductions in capital spending. So we are faced with a contradiction. The outside firm's certification of remaining life requires AEPCO to "expand the capital" and AEPCO acknowledges the need for "increased expenditures." One can only conclude that the current plans to curtail, not expand, capital investment are contrary to the outside firm's assumptions and hence invalidate its conclusion.

A second notable concern in the outside firm's report is the absence of clear and consistent operating assumptions for the two units. The report states that "ST2 and ST3 are typically operated in a load following mode," (Page 2-2), but this of course only recently became true. Projected capacity factors then provided in that report indicate a return to base load operation in 2012 for ST3 and 2015 for ST2, so it appears that the outside firm's determination of remaining life is based on base load operation. One should reasonably assume that remaining life could be different depending on (a) base load operation as assumed, versus (b) load following as suggested by AEPCO's 70 percent CF projection, versus (c) the even lower capacity factors that appear to be the reality.

A third item of concern is the outside firm's notice of at least five equipment replacement recommendations ranging from 1992-2004, none of which have been implemented.[1] We do not

[1] These are noted at various parts of the B&V study and include GT1 stator rewind, ST1 FWH4 replacement, ST2 FWH5 replacement, ST3 FWH6 replacement and ST2/3 ESP upgrades.

question AEPCO's decisions in this regard, but this should beg the question given assumptions on equipment being replaced as necessary in the future.

Finally, and most importantly, the outside firm specifically excluded future environmental requirements from the study. We also assume, although it is not stated, that it did not consider economic restrictions. Since it studied only the physical elements of the plant, both exclusions are appropriate. However, both factors will have a real impact on remaining life.

In summary, the useful life study is not particularly useful in deciding the appropriateness of future capital projects or spending levels.

c. Used and Useful

The general test for rate base inclusion is that the asset be used and useful in the provision of electric service. We have explained earlier that the investment in ST1 does not appear to meet this test. The story is not so clear with respect to ST2 and 3. In summary, however, we have no reason to question the wisdom or appropriateness of AEPCO's recent improvements to ST2 and 3. In fact, some of these have produced tangible O&M savings already.

But one should question how long can investment decisions continue to be justified in the absence of credible underlying assumptions that are known and understood by all, including stakeholders. Questions include:

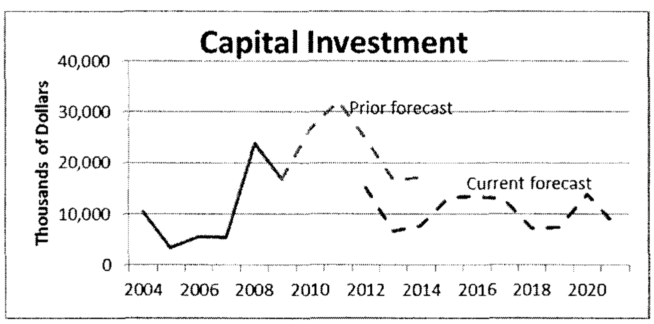
- Is an investment that is justified with an assumption of base load operation still valid with a 50 percent capacity factor?
- Is an investment that assumes a 20-year remaining life still valid with a five-year remaining life?

These questions could and should have been answered after the prior rate case, but remain open today.

2. Future Investments

We have noted that AEPCO has curtailed capital spending and that such a strategy is appropriate lacking better information on the future of the units. While we support such a mitigating measure, we also think it is insufficient and needs to be replaced with the more credible analysis of future requirements discussed previously.

The chart illustrates the significant change in thinking that has taken place in terms of anticipated capital spending at Apache. However, the currently forecasted levels, at more than $10 million per year, are by no means minimal. We reiterate that good decisions are increasingly difficult to make in the planning void that now exists. The potential for bad decisions should be adequately framed by the recent ST1 experience.



RM 1.125

G. Facility Review

Liberty visited the Apache Station and observed the major facilities. Our prior visit, which also encompassed the coal yard, the warehouse and shops, evidenced a plant that is well cared for, well maintained, orderly and professional. This recent visit confirmed and to some extent exceeded that evaluation.

The plant is professionally staffed, with all of the personnel we met hospitable and helpful. The plant manager facilitated our tour and was expert in all facets of the plant and able to fully answer all of our questions while providing insights of interest and value. In addition, we met with key managers and planners and found all to be professional, capable and knowledgeable.

The facilities were clean, above average by power plant standards and there was no real clutter throughout the plant. There appeared to be adequate provisions for maintenance activities, particularly including large, maintenance-friendly turbine floors. We visited the control room for ST2 and 3 and found it professionally staffed and orderly. Access to the plant is controlled by contract security, which appeared to be professional and capable.

In summary, our visit to the Apache Station yielded only positive comments about the facilities and staff at the station.

BEFORE THE ARIZONA CORPORATION COMMISSION

BOB STUMP
Chairman
GARY PIERCE
Commissioner
BRENDA BURNS
Commissioner
BOB BURNS
Commissioner
SUSAN BITTER SMITH
Commissioner

IN THE MATTER OF THE APPLICATION OF THE ARIZONA ELECTRIC POWER COOPERATIVE, INC. FOR A HEARING TO DETERMINE THE FAIR VALUE OF ITS PROPERTY FOR RATEMAKING PURPOSES, TO FIX A JUST AND REASONABLE RETURN THEREON AND TO APPROVE RATES DESIGNED TO DEVELOP SUCH RETURN	)	DOCKET NO. E-01773A-12-0305

REDACTED

DIRECT

TESTIMONY

(PURCHASED POWER and FUEL ADJUSTOR CLAUSE REVIEW)

OF

JOHN ANTONUK

(CONSULTANT)

ON BEHALF OF THE STAFF OF THE

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

MAY 1, 2013

TABLE OF CONTENTS

EXHIBIT

INTRODUCTION

Q State your name, position, and business address.

A. My name is John Antonuk. I am president of The Liberty Consulting Group ("Liberty"). My Liberty business address is: The Liberty Consulting Group, 65 Main Street, P.O. Box 1237, Quentin, Pennsylvania 17083.

Q. Mr. Antonuk, briefly summarize your education background and professional qualifications as they relate to the subject of your testimony.

A. I began my career in service to the Commonwealth of Pennsylvania, first as an investigator with the Attorney General's office (investigating major issues in or contemplated to be in affirmative civil litigation), and then as Assistant Counsel to the Pennsylvania Public Utilities Commission. Then, for several years, I headed a group in the Regulatory Affairs Department of Pennsylvania Power & Light Company (now PPL). After serving for a number of years as the head of the litigation consulting practice for a major west coast management consulting firm, I was one of the founders of Liberty, which is now approaching a quarter century of service. I have managed or provided executive direction to two hundred or more Liberty projects, working in virtually every U.S. State and serving two-thirds of the country's utility regulatory authorities. My work has involved investor-owned, cooperative, public authority and municipally-owned electricity, natural gas, and telecommunications utilities. I have led or conducted work involving nearly every facet of utility governance, management, operations, finance, rate and regulatory, and corporate support.

Addressing energy utility fuel and energy management and operations performance has been an area of particular emphasis, not only in my assignments with Liberty, but also in my tenure with the public utility commission and a major electric utility in Pennsylvania. My work in fuel procurement and management began in the immediate aftermath of the first Mideast oil embargo in the early 1970s; it has continued throughout many engagements across my time with Liberty.

I am an honors graduate of Dickinson College and the Dickinson School of Law.

Q. Have you prepared a more detailed summary of your background?

A. Yes; Exhibit JEA-1 provides it.

Q. What is the purpose of your testimony?

A. Liberty performed under my overall direction: (a) an examination of the prudence of fuel, purchased power, and plant operations policies, activities, and costs of Arizona Electric Power Cooperative, Inc. ("AEPCO" or "Cooperative"), and (b) an engineering review of AEPCO's facilities. Exhibit JEA-2 provides the PPFAC report. Richard Mazzini is also appearing as a witness to present the Engineering Analysis/Plant Operations report. Mr. Mazzini had direct responsibility for conducting the activities and conclusions and recommendations described in that exhibit.

Q. What was the scope of the liberty review described in Exhibit JEA-2?

A. Liberty addressed the following areas established by an Arizona Corporation Commission Request for Proposal ("RFP") that set the scope for the examination that Liberty performed.

Liberty divided our work and the subsequent report into the following areas:

- Fuel Oils and Natural Gas
- Coal
- Power Transactions
- PPFAC Mechanism Review

- Power Plant Operations (which is covered together with Liberty's Engineering Analysis and filed under separate cover.)

Q. Does that conclude your Direct testimony?

A. Yes, it does.

John Antonuk Resume

Areas of Specialization

Executive management; management audits and assessments; service quality and reliability management and measurement, utility planning and operations; litigation strategy; management of legal departments; human resources; risk management; regulatory relations; affiliate transactions and relations; subsidiary operations; and testimony development and witness preparation.

Relevant Experience

Electricity

Project Director and lead consultant for Corporate Planning on Liberty's management and operations audit of Iberdrola SA/Iberdrola USA/NYSEG and RG&E for the New York Public Service Commission.

Project Director and lead consultant for Governance and Senior Management on Liberty's management and operations audit of Interstate Power and Light for the Iowa Utilities Board.

Project Director and lead consultant on Liberty's management and operations audit of the electricity, natural gas, and steam operations of ConEd for the New York Public Service Commission.

Project Director on Liberty's benchmarking analysis of Arizona Public Service for the Arizona Corporation Commission. This study covered a ten-year audit period and benchmarked Arizona Public Service's performance with the following metrics: Operational Performance, Cost Performance, Financial Performance, Affiliate Expenses, and Hedging & Risk Management.

Project Manager for Liberty's comprehensive, detailed affiliate relationships and transactions audit of Duke Energy Carolinas for the North Carolina Utilities Commission staff.

Project Manager for the performance of Liberty's audit for the Delaware Public Service Commission of a diagnostic audit of the affiliate costs borne by Delmarva Power, a member of the multi-state holding company, PHI. This review included an examination of the central services organization structure and operations, the procedures and methods used to allocate and assign costs, and test work to verify that execution of methods and procedures conforms to company procedures and to good utility practice.

Project Manager for Liberty's work for NorthWestern Energy to formulate long-range integrated infrastructure plans for its multi-state electric and natural gas distribution utilities. This project includes consideration of how to incorporate "Smart Grid" technology into infrastructure plans in a manner that will enable the Company to roll out new capabilities and services as technology makes them available, without undue acceleration of capital spending as uncertainties in this new marketplace become resolved.

Project Manager for Liberty's audit of Arizona Electric Power Cooperative for the Arizona State Corporation Commission which included reviews of fuel procurement and management, bulk electricity purchases and sales, power plant management, operations and maintenance, energy clause design and operation, and other issues affecting the prudence, reasonableness, and accuracy of costs that pass through the fuel and energy clause.

Project Manager for Liberty's audit of Southwest Transmission Cooperative for the Arizona Commission, a companion examination of the transmission cooperative that is owned and operated in parallel with Arizona Electric Power Cooperative (a generation cooperative). Among the issues examined in this audit were line losses.

Project Manager for Liberty's audit of Southwestern Public Service (SPS) for the New Mexico Public Regulation Commission that included a management review of the prudence of SPS' transactions under the Renewable Energy Credit tracker as conditionally approved by the Commission and a financial review of both revenues and expenses in order to provide an analysis of any under-recovery or over-recovery. Similarly, Liberty performed an evaluation of SPS' fuel clause process and regulations and a financial audit of fuel clause computation. In addition, reviews of purchases of coal, natural gas, oil, and purchased power, power plant operations, line losses, and cost allocation and assignment were also performed.

Project Manager for Liberty's audit of East Kentucky Power Cooperative, which included examinations of Governance, Planning, Finance, and Budgeting. Liberty performed for the Kentucky Public Service Commission an examination of governance at a generation and transmission cooperative serving 16 distribution cooperatives across the state. This study came in the wake of significant financial difficulties and also addressed planning, budgeting, financial, and risk functions and activities.

Project Manager for Liberty's audit for the Virginia State Corporation Staff of Potomac Edison Distribution System Transfer. Liberty examined the public interest questions associated with the transfer by an Allegheny Energy's utility operating subsidiary (Potomac Electric) of all of its electricity distribution operations business and facilities in Virginia to two rural electric cooperatives.

Project Manager for Liberty's audit of the fuel and purchased-power procurement practices and costs of Arizona Public Service Company for the Arizona Corporation Commission. Liberty completed audits relating to fuel procurement and management and on rate and regulatory accounting for related costs at Arizona Public Service Company for the Arizona Corporation Commission.

Project Manager for Liberty's audit of Duke Energy Carolinas for the North Carolina Utilities Commission. Scope included compliance with regulatory conditions and code of conduct imposed by the Commission after the merger with Cinergy, and affiliate transactions and cost allocation methods.

Project Manager for Liberty's audit of affiliate transactions of Nova Scotia Power on behalf of the Nova Scotia Utility and Review Board.

Project Manager for Liberty's audit for the New Jersey Board of Public Utilities of the competitive service offerings of the state's four major electric companies. Scope included corporate structure, governance, and separation, service company operations and charges, inter-affiliate cost allocations, arm's-length dealing with respect to a variety of code-of-conduct requirements, and protection of customer and competitor proprietary information.

Project Manager and witness for the staff of the Arizona Corporation Commission addressing the merits of the proposed acquisition of UniSource by a group of private investors.

Project Manager and witness before the Oregon Public Utility Commission addressing the merits of the proposed acquisition of Portland General Electric by a group of private investors.

Engagement Director for Liberty's provision of engineering and technical assistance to the Vermont Public Service Board in connection with review of public necessity and convenience related to the Northwest Reliability Project, which would add a major new 345kV transmission plan to provide an additional source of electricity to serve Vermont's major load growth in its northwest region. The project involved transmission reinforcements at lower voltages and significant substation upgrade work. The proceedings had numerous public, private, and government interveners, who raised issues regarding project need, available electrical alternatives, routing and design, and electromagnetic radiation.

Project Manager for Liberty's support for the New Hampshire Public Utilities Commission in its charge to oversee the divestiture of the Seabrook nuclear plant as part of a major restructuring settlement. The sale produced record high compensation for nuclear facilities in the country.

Project Manager and witness for Liberty's assessment of fuel procurement, affiliate transactions, and automatic adjustment clause implementation for the staff of the Nova Scotia Utility and Review Board in rate case of Nova Scotia Power.

Project Manager for Liberty's engagement on behalf of Boston Edison to examine the company's affiliate relations, including issues of the valuation of assets transferred to an affiliate. Testified in proceedings before the Massachusetts Department of Telecommunications and Energy (formerly the Department of Public Utilities) on several telecommunications issues, including: (a) development of competition, and legislative and regulatory-policy changes supporting it, (b) electric-utility entry into telecommunications markets, (c) costs, prices, and market value of network elements, (d) requirements of the Telecommunications Act of 1996, (e) assessment of compliance with commission orders, company procedures, and service agreements regarding limits on affiliate interactions, (f) inter-company loans, guarantees, and credit support among utilities and their affiliates, (g) accounting for affiliate transactions, (h) obligations to allow nondiscriminatory access to network infrastructure to third parties, and (i) cost pools, overhead factors, and allocation of common costs among utility and non-utility affiliate activities and entities.

Project Manager for Liberty's major consulting engagement for the New Hampshire Public Utilities Commission. Liberty examined management, operations, and costs at Public Service Company of New Hampshire/Northeast Utilities, which is engaged in the operational and cost-accounting separation of its network into segments, for the purposes of restructuring service offerings to allow competition in certain aspects of electric-energy supply. This engagement included an assessment of valuations of nuclear and fossil units, as well as supply contracts with independent-power producers. Liberty also assisted in efforts to settle rate case and restructuring disputes involving, among other issues, stranded costs associated with power plants. The scope of Liberty's work included the development of plans and protocols for power plant (fossil, hydro, and nuclear) and power supply contract assets, as well as the oversight of activities associated with asset auctions.

Engagement Director for Liberty's evaluation of corporate relations and affiliate arrangements of Dominion Resources, Inc. and Virginia Power for the Virginia State Corporation Commission. This project addressed all significant aspects of corporate governance, operating relationships, and affiliate arrangements between the two entities.

Project Director for Liberty's evaluation of a report prepared by a consultant to the Hawaii Public Utilities Commission on the relationship between Hawaiian Electric Industries (HEI), a diversified utility-holding company, and Hawaiian Electric Company (HECO), its principal subsidiary and operating electric utility.

Project Director for all aspects of Liberty's comprehensive management and operations audit of West Penn Power Company for the Pennsylvania Public Utilities Commission. Managed focused reviews of the Company's affiliated costs, power dispatch and bulk power transactions, customer services, finance, and corporate services. Presented testimony before the PAPUC on behalf of the Office of Trial Staff regarding the results of the audit in West Penn's rate case.

Lead Consultant for affiliate relations for Liberty's assignment of providing assistance to Delmarva Power & Light Company in developing and implementing self-assessment and continuous-improvement processes.

Project Director for Liberty's reviews of fossil-fuel procurement and administration in Liberty's management/performance audits of the Centerior Energy Company's operating companies - Cleveland Electric Illuminating Company and Toledo Edison Company - and Ohio Edison, Monongahela Power (an Allegheny Power System operating company), and Cincinnati Gas & Electric, for the Public Utilities Commission of Ohio.

Served as advisor to the administrative law judge of the Delaware PSC responsible for hearing cases regarding the implementation of the new law that restructures the electric-utility industry in Delaware.

Engagement Director for nuclear plant performance-improvement projects that Liberty conducted for Duquesne Light Company, Centerior Energy, Nebraska Public Power District, and Pennsylvania Power & Light Company (PP&L).

Engagement Director for a Liberty assignment for Florida Power Corporation, regarding a proposal by the Tampa Electric Company to construct transmission lines to serve the cities of Wauchula and Fort Meade, Florida. Liberty's testimony helped convince the Florida Public Service Commission that Tampa Electric Company's proposed line was uneconomic.

Directed Liberty's engagement to assist a regional electric generation and transmission cooperative, whose members' combined operations make it a major competitor in the state's electricity business, to conduct its first-ever comprehensive and formal strategic-planning process.

Natural Gas

Project Manager for Liberty's examination of safety programs and activities of NiSource's Maine subsidiary Northern Utilities for the Maine Public Service Commission.

Project Manager for Liberty's focused and general management audits of NJR, New Jersey Natural Gas, and affiliates for the New Jersey Board of Public Utilities. This project included detailed examinations of affiliate relationships, governance, financing and utility ring-fencing, compliance with New Jersey EDECA requirements for affiliate separation, protection of confidential information, non-discrimination against third-party competitors with utility affiliates, and other code-of-conduct issues. Personally performed the reviews of governance, EDECA requirements compliance, and legal services.

Project Manager on a major focused audit of Peoples Gas/Integrys that Liberty performed for the Illinois Commerce Commission. Audit topics included natural gas forecasting, portfolio design and implementation, gas purchase and sale transactions, controls, organization and staffing, asset management, off-system sales, storage optimization, and all other issues related to gas supply over a period of eight years.

Project Manager and witness on three recent audits of fuel (primarily coal and natural gas) procurement and management practices of Nova Scotia Power, a review of the merits and mechanics of a company-proposed automatic recovery method for energy costs, and an audit of affiliate relationships (including coal, electric power, and natural gas procurement activities) performed for the Nova Scotia Utility and Review Board.

Project Manager for Liberty's focused and general management audits of SJI, South Jersey Gas, and affiliates for the New Jersey Board of Public Utilities. This project included detailed examinations of affiliate relationships, governance, financing and utility ring-fencing, compliance with New Jersey EDECA requirements for affiliate separation, protection of confidential information, non-discrimination against third-party competitors with utility affiliates, and other code-of-conduct issues. Personally performed the reviews of governance, EDECA requirements compliance, and legal services.

Project Manager for Liberty's work with staff of the Virginia State Corporation Commission to evaluate the services of an affiliate providing gas portfolio management services under an asset management agreement with Virginia Natural Gas, an operating utility subsidiary of Atlanta-based AGLR.

Project Manager for Liberty's focused audit of NUI Corporation and NUI Utilities. This audit included a detailed examination of the reasons for poor financial performance of non-utility operations, downgrades of utility credit beneath investment grade, and retail and wholesale gas supply and trading operations. Also examined performance of telecommunications, engineering services, customer-information-system, environmental, and international affiliates. The audit included detailed examinations of financial results, sources and uses of funds, accounting systems and controls, credit intertwining, cash commingling, and affiliate transactions, among others. Liberty's examination included very detailed, transaction-level analyses of commodities trading undertaken by a utility affiliate both for its own account and for that of utility operations.

Project Manager for Liberty's comprehensive management audit of United Cities Gas Company for the Tennessee Public Service Commission. Responsible for the focused reviews of affiliate interests, executive management and corporate planning, and vehicle management.

Lead Consultant in Liberty's management audit of Connecticut Natural Gas Company for the Connecticut Department of Public Utility Control (DPUC). Responsible for reviews of organization and executive management and legal management.

Lead Consultant in Liberty's management audit of Southern Connecticut Gas Company for the DPUC. Responsible for organization and executive management, affiliates, and legal management. Included valuation of a major, rate-based LNG facility being offered for sale.

Directed Liberty's management audit of Yankee Gas Services Company for the DPUC.

Engagement Director for Liberty's evaluation of regulatory needs and alternatives for the Georgia Public Service Commission in regulating the state's local-gas-distribution companies in the aftermath of FERC Order 636.

Project Director for Liberty's review of gas-purchasing policies and practices at Pike Natural Gas Company and Eastern Natural Gas Company for the Public Utilities Commission of Ohio. Responsible for the review of organization and staffing and regulatory-management issues.

Combination Utilities

Engagement Director for Liberty's examination of the cost-allocation methods of Baltimore Gas & Electric Company and its affiliates for the Maryland Office of People's Counsel.

Project Director for Liberty's focused management audit of affiliate transactions of Public Service Electric & Gas Company (PSE&G) and the unregulated subsidiaries of Public Service Enterprise Group, Inc., the parent, for the New Jersey Board of Regulatory Commissioners. Task leader for the review of organization and planning, and executive management.

Project Director for Liberty's management and operations audit of New York State Electric & Gas Corporation for the New York Public Service Commission (NYPSC). Responsible for managing the review of corporate planning and organization, service centralization, specific corporate services, and finance and accounting.

Project Director for Liberty's management and operations audit of Central Hudson Gas & Electric Corporation for the NYPSC.

Telecommunications

Arbitrator named by the District of Columbia Public Service Commission to address industry-wide need for amendments to interconnection agreements as a result of the FCC's Triennial Review Order.

Project Manager for assistance being provided to the Administrative Law Judge of the Delaware Public Service Commission hearing the arbitration to address industry-wide need for amendments to interconnection agreements as a result of the FCC's Triennial Review Order.

Project Manager for Liberty's engagement to serve as advisors to commissioners of the District of Columbia Public Service Commission in their review of the Section 271 application of Verizon to provide in-region, interLATA service in the District.

Project Manager for Liberty's engagement to serve as advisor to the administrative law judge of the Delaware Public Service Commission in the review of the Section 271 application of Verizon to provide in-region, interLATA service in the state.

Retained by the Idaho Public Utilities Commission to serve as administrative law judge in complaint proceedings involving three paging companies and Qwest, involving a variety of financial disputes arising out of interconnection and tariff purchases.

Conducted wholesale performance metrics training for staff members and commissioners of the Pennsylvania Public Utility Commission as part of efforts to monitor service quality and payments under the Verizon Performance Assurance Plan adopted in connection with the RBOC's entry into the in-region inter-LATA market in Pennsylvania.

Engagement Director for Liberty's comprehensive financial review of Verizon New Jersey Inc. (VNJ) for the New Jersey Board of Public Utilities. The review had three parts: a financial evaluation; a review of merger costs and savings; and an assessment of affiliate costs and transactions.

Engagement Director for Liberty's audit of Ameritech-Ohio policies, procedures and compliance with service quality performance requirements under Ohio's Minimum Telephone Service Standards.

Engagement Director for Liberty's audit of Qwest's performance measures for the Regional Oversight Committee (ROC). Responsible for the evaluation of the processes and data tracking of several hundred wholesale and retail performance indicators including service areas such as provisioning, OSS access, maintenance and repair, and billing.

Project Manager and hearing administrator for Qwest's 271 hearings for the commissions of Idaho, Iowa, Montana, New Mexico, North Dakota, Utah, and Wyoming.

Engagement Director for Liberty's assistance provided to the Staffs of the Virginia State Corporation Commission and the New Jersey Board of Public Utilities in the implementation of the 1996 Telecommunications Act.

Project Manager for Liberty's assistance to Delaware PSC arbitrators in seven different interconnection cases arising out of the Telecommunications Act.

Served on an arbitration board in Mississippi, and as the sole arbitrator in two cases in Idaho regarding interconnection agreements between incumbent local-exchange companies and new entrants to the local telephone market.

Engagement Director for Liberty's work determining permanent prices for the unbundled-network elements of Southwestern Bell Telephone for the Oklahoma Corporation Commission.

Engagement Director for Liberty's provision of arbitration services to the North Dakota Public Service Commission and Nebraska Public Service Commission in cases involving implementation of the Telecommunications Act of 1996.

Engagement Director for Liberty's combined comprehensive management/affiliate-relations audit of Bell Atlantic - Pennsylvania for the PAPUC, and affiliate relations audit of Bell Atlantic - District of Columbia for the Public Service Commission (DCPSC) of the District of Columbia. Served as team leader with responsibility for the coordination of the review of executive management, finance, and support services.

Engagement Director for Liberty's examination of the accounting and allocation on lobbying costs of Bell Atlantic for an eight-year period for the DCPSC. Engagement included an examination of the propriety of policies and procedures for assigning and allocating lobbying costs.

Engagement Director for a management audit of GTE South, Inc. for the Kentucky Public Service Commission. This examination included a review of GTE's affiliate transactions.

Project Director for Liberty's evaluation of New York Telephone's transactions with affiliates for the NYPSC. Responsible for the review of affiliates involved in directories publishing, government affairs, international activities, information services, and the legal-affairs entity.

Project Director for Liberty's management audit of the affiliated interests of C&P Telephone of Maryland performed on behalf of the Maryland Public Service Commission.

Engagement Director for Liberty's two assignments for the DCPSC in reviewing Bell Atlantic - District of Columbia's construction-program planning and quality-of-service standards.

Other Companies

Set up and managed service and facilities section of the PP&L Regulatory Affairs Department. Counseled utility management on regulatory and legislative matters. Litigated rate related and facility construction proceedings before agencies and the courts.

Attorney for the PAPUC. Assigned as counsel to the Commission's Audit Bureau in developing a comprehensive management-audit system. Negotiated contracts for the first commission-ordered management audits in Pennsylvania. Revised Commission organization and practice to conform to regulatory-reform legislation.

Testimony

Nova Scotia Utility and Review Board – Testimony on the prudence of fuel procurement, affiliate relationships associated with fuel management, and use of an automatic adjustment clause to recover fuel costs.

Arizona Corporation Commission – Testimony on the merits and conditions of the proposed acquisition of UniSource by private investors.

Oregon Public Utility Commission – Testimony on the merits and conditions of the proposed acquisition of Portland General Electric by private investors.

Virginia State Corporation Commission - Testimony in arbitration cases regarding interconnection agreements between Bell Atlantic - VA and competing local exchange companies.

PAPUC - Presentation of management-audit recommendations and benefits for selected conclusions in West Penn Power Company request for rate increase.

Maryland Public Service Commission - Presentation and defense of management-audit conclusions, recommendations, and cost implications in C&P Telephone Company of Maryland (Bell Atlantic) rate case.

Illinois Commerce Commission - Testimony about fuels organization, procurement, and management in fuel-cost reconciliation proceedings.

Maryland Public Service Commission - Testified regarding Baltimore Gas & Electric Company's affiliate relations.

Tennessee Regulatory Authority - Testified regarding Liberty's recommendations in a management audit of United Cities Gas Company.

Education

J.D., with academic honors, Dickinson School of Law
B.A., cum laude, Dickinson College

REDACTED
Review of AEPCO Fuel, Purchased Power, and PPFAC Management

Presented to the:

Arizona Corporation Commission

By:

THE LIBERTY CONSULTING GROUP

65 Main Street
Quentin, Pennsylvania 17083

(717) 270-4500 (voice)
(717) 270-0555 (facsimile)
Admin@LibertyConsultingGroup.com (e-mail)

April 29, 2013

Table of Contents

I. Introduction

A. Background

The Liberty Consulting Group ("Liberty") conducted for the Staff of the Arizona Corporation Commission ("the Commission") an examination of fuel, purchased power, and plant operations policies, activities, and costs of Arizona Electric Power Cooperative, Inc. ("AEPCO" or "the Cooperative"), based in Benson, Arizona.

Liberty is a management, operations, technical, and regulatory consulting firm that specializes in the energy and telecommunications utility businesses. Liberty has served more than two-thirds of the country's utility regulatory authorities (and a number of others in North America) over a more than 25-year history. Liberty's work has included many examinations of electric utility fuel, power purchase, and power production management, operations, and prudence for regulators across the country. Liberty has also performed extensive work in the examination of fuel and purchased power cost recovery through adjustment clauses, focusing on clause design, operation, and accuracy.

Liberty conducted this review in the context of an AEPCO rate filing before the Commission at Docket No. E-01773A-12-0305.

B. Project Objectives and Scope

The objective of Liberty's review was to verify that AEPCO has acted prudently and reasonably in assuring cost and operational effectiveness in these areas. Liberty's examination included the following areas identified in the Request for Proposals ("RFP"):

- Audit AEPCO's fuel and purchased power costs during the test year.
- Determine if there have been declines in operating availability, equivalent availability, or capacity factors of the generating plants owned by AEPCO and, if so, determine any impact of such decline on ratepayers.
- Calculate a base cost of fuel and purchased power to be used prospectively.
- Review AEPCO's proposed changes to its PPFAC mechanism.
- Make any necessary changes to the PPFAC Plan of Administration.

C. Task Structure

Liberty created the following task structure to facilitate its examination of the 18 included areas:

- Fuel Oils and Natural Gas
- Coal
- Power Transactions
- PPFAC Mechanism Review
- Power Plant Operations (which is covered together with Liberty's *Engineering Analysis* and filed under separate cover.

II. Fuel Oils and Natural Gas

A. Background

AEPCO's steam units generally run on coal, and its combustion turbines generally run on natural gas. An AEPCO combined-cycle unit also runs on gas. AEPCO modified Unit ST2 to burn gas in 1989; it similarly modified ST3 in 1993. At those times, AEPCO tested both units on gas for several months (ST2) or several weeks (ST3), and then resumed firing them with coal. ST3 switched to gas at the end of January 2012 to take advantage of low gas prices. It burned gas for about five months, and then returned to coal in early July.

AEPCO's gas turbines can use fuel oils as an alternative to natural gas. Steam Unit No. 1 could burn fuel oils. Fuel oils fed the igniters for the coal units. Gas has been available and competitively priced, so there has been no need to use fuel oils as generating fuels. AEPCO switched the igniters to natural gas in the 1980s.

GT4 has a 130,000 gallon tank for fuel-oil storage. This sizing provides 48 hours of operation at full load if operating on oil. Only "minimal" quantities are kept in the tank, however, because local fuel oil dealers can re-supply it quickly if necessary. Diesel fuel, kept in a smaller, 10,000-gallon tank, powers trucks and heavy equipment moving coal at Apache Station.

Liberty reviewed AEPCO's use of fuel oils and natural gas in the Test Year (2011), and the Cooperative's adjustments to Test-Year costs to account for "known and certain" changes in those costs. This chapter presents our findings and conclusions.

B. Findings

The Company reports that it out-sourced its scheduling and trading functions to ACES Power Marketing LLC (APM) in May 2011. APM had previously performed a number of functions for AEPCO, including:

- Counterparty credit analysis and exposure monitoring;
- Contract negotiation and administration;
- Trading controls, including trade capture and validation, and policy compliance monitoring; and
- Risk management, including policy development and implementation.

The additional functions transferred consisted of portfolio management and operations, including generation-unit scheduling, and power and natural-gas trading.

APM formed a Western Region Trading Center, which is located in AEPCO's offices. AEPCO's generating units are scheduled and dispatched from there. Natural gas purchasing occurs at APM's home office in Indiana.

Fuel-supply planning occurs under a joint effort between AEPCO and APM. The member cooperatives submit load forecasts, which are checked for consistency and aggregated by a consultant (C. H. Guernsey). Those aggregated load forecasts are then run through a dispatch-simulation computer model by APM to forecast:

Generation by each of AEPCO's generating units

Purchase requirements under each of AEPCO's long-term power-purchase contracts.

The forecasts initially cover the next five years, and then undergo multiple updates during the year. These activities occur as part of AEPCO's budgeting and business-planning processes.

The generation forecasts also produce estimates of requirements for generating fuels. Fuel prices and forward power prices within AEPCO's power-coordination area serve as inputs to the forecasting process. Outputs therefore include possible economy power purchases and sales, as well as quantities of fuel required, if power purchases or sales are indicated by relative price levels. Through this process, AEPCO generates fuel-requirements forecasts by month for the next five years.

In the 2010 Rate Case, AEPCO proposed, and the Commission agreed, to segregate its power-supply resources into "Base Resources" and "Other Resources." Base Resources are the Company's two large steam units (ST2 and ST3), currently operating on coal, plus its power-purchase contracts from hydroelectric projects. Other Resources include its gas-fired generation and market purchases. Some natural gas is used for flame stabilization in the coal-fired units; that gas is classified to Base Resources. Similarly, the diesel fuel used to power coal-handling equipment is considered a Base Resource fuel expense. Its cost flows through the Base Resource PPFAC. Costs incurred for natural gas requirements above those for flame stabilization, if any, flow through the Other Resources component of the PPFAC. As discussed below, most of the diesel fuel that is not in Base Resource fuel expense is assigned to capital projects.

AEPCO no longer has a natural gas hedging plan. The hedging plan was terminated due to the fact that the Partial Requirements Members ("PRMs") decided to hedge their own exposure to natural gas and power prices. AEPCO is still responsible for hedging natural gas prices for the All Requirements Members ("ARMs"). At the time that the hedging plan was terminated, however, AEPCO had hedged some gas through 2013. Because the hedging needs of the ARMs are small, no additional hedges are needed at this time.

Operationally, APM schedules AEPCO's generating units, and optimizes the use of AEPCO's generating and fuel-purchase resources through power and gas trading. Gas is either burned in the gas-fired units at Apache Station or sent to storage for future use. Power is generated, bought, or sold, depending on AEPCO's marginal costs of generation relative to power-market prices. APM tracks the gas purchases, and provides AEPCO's Energy Services unit with a monthly report that verifies the amount to be paid to each vendor. Energy Services reviews and approves invoices for payment.

Quantities of gas delivered, as measured by the pipeline, are compared to usage by the generating units. Comparisons use hourly data. When discrepancies are noted, meters are recalibrated.

1. Fuel Oils

In the test year (2011), AEPCO used almost 56,000 gallons of diesel fuel. Total cost was $170,998. Almost 80 percent of that amount was classified as a fuel cost, and forms part of the Base Resources fuel cost. Most of the other expenditures for fuel oils in that year were assigned to various capital projects. Those projects included a major boiler-tube overhaul and a steam-turbine overhaul. The Company's filing includes no adjustments to these costs going forward.

AEPCO retains on its property the 11,000,000 gallons of fuel-oil storage facilities that Liberty reported in 2010. The higher cost of fuel oils and the age of AEPCO's generating units that are capable of burning fuel from those tanks led AEPCO to close all storage tanks, with the exception of the 130,000-gallon tank associated with GT4, and the 10,000-gallon tank used to supply heavy equipment.

AEPCO's inventory-control practices for its diesel fuel are reported to be the same as they were when Liberty reviewed them in 2010. External audits have revealed no issues with either inventory levels or inventory-management processes since Liberty's prior review. The Company reports that internal audits have not recently addressed these subjects.

2. Natural Gas

a. Fixed Gas Costs

<u>Pipeline Capacity</u>
AEPCO's Apache Generating Station is served exclusively by the El Paso Natural Gas Pipeline system ("El Paso"). El Paso's rates and services were restructured in its 2006 rate case before the Federal Energy Regulatory Commission ("FERC"). As a result of that restructuring, AEPCO changed from "all-requirements" service to a combination of conventional gas-transportation contracts and contracts for "premium" services. The latter allow AEPCO to take its maximum contracted quantities over 8 or 12 hours, rather than the usual 24 hours.

The contracts entered as a result of El Paso's restructuring expire in 2016. El Paso's charges increased in 2011 as a result of a rate case. Charges to AEPCO went from $4,761,759 to $4,954,965 per year, an increase of $193,206.

<u>Natural Gas Storage</u>
Natural gas storage on the El Paso system is only available to shippers from the Keystone Storage facility, located near the border between west Texas and eastern New Mexico, and owned by Chevron. El Paso has some storage, but utilizes it fully to support the services it provides. AEPCO has had a contract for storage service from the Keystone facility, but re-evaluated its requirement for the service in late 2011, as its contract was expiring at the end of the 2011/2012 withdrawal season (March 31, 2012).

AEPCO asked APM to assist in evaluating whether to renew the service. The analysis evaluated three scenarios:

- [redacted]

- [redacted]

The analysis also covered two cases:

- [redacted]

[redacted] That option was judged to allow for continued operational flexibility and certainty, while potentially providing a cost savings [redacted] AEPCO entered a new three-year contract for half the storage capacity and injection/withdrawal capacities provided by the previous one. The fixed costs of the new contract are a little less than half of those in the previous one, but the per-unit injection and withdrawal costs are the same. AEPCO estimates that the total cost going forward will be $241,359 less than the cost in the Test Year.

Total Fixed Gas Costs

AEPCO considers the changes in pipeline and storage charges to be "known and certain"; thus, both of those changes resulted in adjustments to Test Year costs. The net adjustment was a reduction of $48,153.

b. Gas Commodity Costs

AEPCO continues to buy natural gas under standard form contracts developed by the North American Energy Standards Board ("NAESB") and the Gas Industry Standards Board (GISB). AEPCO presently has active NAESB contracts with 13 counterparties, and GISB contracts with three. Since May 2011, all transactions under those contracts have been scheduled, executed and tracked by APM.

c. "Base" and "Other" Gas Costs

The fixed and variable gas costs incurred in 2011, divided between Base and Other components of AEPCO's costs, are presented in the tables on the next two pages. As noted, AEPCO is proposing to reduce its fixed costs by $48,153, and reallocate them among its members as approved by the Commission in Decision No. 72735. The allowance for variable costs will stay the same.

Base Gas Costs

[redacted]

Other Gas Costs

[redacted]

C. Conclusions

1. The Company's allowance for the cost of fuel oils in the Base Cost of Fuel and Purchased Power is acceptable.

The Company proposes no adjustment to its fuel oils expense. Eighty percent of this cost is diesel fuel to power coal-handling equipment at Apache Station. If the amount of coal consumed in ST2 and ST3 changes, the quantity of diesel used to move the coal will likely change. Whether the change will be proportional to the change in coal consumption is not clear, however, and the effect of the change in overall fuel costs, or even Base Fuel Costs, will be small.

Diesel-fuel prices going forward are not materially different from what they were in the Test Year. Inventory management practices are the same as in 2010, with no issues reported in either internal or external audits. Thus, Liberty proposes no change in the amount of this expense at this time.

2. The Company's reduction in its contract for natural gas storage services is reasonable.

The Company's contract for this service expired at the end of the 2011/2012 withdrawal season. Prior to that time, it analyzed its continuing requirement for that service, with APM's help. The analysis included several options, and considered both partial-requirements and all-requirements customers' needs. The analysis supported reducing the service, which was done. The decision was reasonable, and the proper adjustment was made to AEPCO's costs for the purpose of setting its Base Fuel Costs.

3. The Company's allowance for the cost of natural gas in the Base Cost of Fuel and Purchased Power is acceptable.

The Company has proposed a reduction of $48,000 in its fixed gas costs, resulting from offsetting changes from Test-Year costs:

- An increase of $193,000 in pipeline fixed costs, due to an increase in El Paso's rates
- A decrease of $241,000 in storage costs, due to a decrease in the amounts of storage services under contract.

Both of these changes are considered "known and certain."

The commodity cost used in the filing is [redacted] per MMBtu. The price of natural gas has fallen considerably since that time. As this report is being written (late February 2013), the forward prices for the six months beginning November 1 of this year average about $3.80 per MMBtu, or a little over [redacted] per MMBtu lower than the cost in the filing. AEPCO personnel are aware of this change; they do not propose an adjustment, however, because they do not consider futures prices to be a "known and certain" change.

At this time, Liberty does not propose an adjustment.

D. Recommendations

Liberty has no recommendations in this area.

III. Coal

A. Background

This chapter addresses the following areas related to coal use at AEPCO:

Fuel Burned — Sources — Prices
Contract Actions — Transportation — Inventory
Contract Purchases and Summaries

B. Findings

1. Coal Forecast Versus Actual Consumption

AEPCO burns coal at the two units of the Apache Generating Station (Apache). Rail transportation provides the primary transport method for coal consumed by AEPCO to generate electricity at Apache. AEPCO receives coal under a combination of long-term and short-term (or "spot") fuel supply contracts. Long-term contracts consist of obligations whose terms equal or exceed one year; spot agreements have durations of less than a year. Each Apache coal unit (ST2 and ST3) has a net rating of 175 MW. Together, their annual coal consumption has recently run in the 1.2 million ton range.

AEPCO burns low sulfur western coals from the Wyoming Powder River Basin ("PRB"), from Western Colorado, and from New Mexico. These coals range in sulfur content from a low of approximately 0.36 percent for Western Colorado coal to 0.93 percent for New Mexico coal.

The following table summarizes the annual comparisons between coal burn forecasts and actual coal burned at Apache from 2010 through 2012:

Coal Consumption: Forecast Versus Actual

Item	2010	2011	2012
Forecast Tons	[redacted]	[redacted]	[redacted]
Actual Tons	[redacted]	[redacted]	[redacted]
Difference – Tons	[redacted]	[redacted]	[redacted]
Difference - Percent	[redacted]	[redacted]	[redacted]

The next graph shows total coal consumption in tons, by month from January 2010 through December 2012. The graph compares this actual burn information with AEPCO's forecasts of burns for each month.

Actual versus Forecast Coal Consumption

[redacted]

The preceding graph and table show reasonable correlation between forecast and actual coal consumption for 2010. For 2011, the variation was in the same direction, with the forecast being higher than actual, but with an 8 percent difference between forecast and actual. For the year of 2012, the difference was in the opposite direction, with actual consumption being 30.0 percent higher than forecast. This variance is very high. This divergence is due mainly to natural gas prices which differed greatly from expectations during 2011 and 2012.

2. Coal Sources

The following graph shows the relative distribution of AEPCO's three supply sources from 2008 through 2012: the Powder River Basin of Wyoming, Western Colorado, and New Mexico. The graph makes apparent the dramatic shift in coal supply sources that took place in 2009 because of overall coal supply economic considerations. In 2010 and 2011, deliveries came entirely from New Mexico under the Peabody COALSALES Contract. Deliveries amounted to approximately 1,025,000 tons per year.

In November 2011, AEPCO received a decision from the Surface Transportation Board (STB) in a rail rate case addressing transportation rates for the New Mexico, Northern Powder River Basin and Montana coal origins served by the BNSF Railway. Because of more favorable rail rates, in 2012 AEPCO began using new supplies of coal from Wyoming as discussed below in Section 4. AEPCO's 2012 coal deliveries amounted to [redacted] tons from New Mexico, and [redacted] tons from Wyoming. Coal deliveries in 2012 fell significantly below 2010 and 2011 levels as low priced natural gas and purchased power displaced own generation, and as AEPCO sought to reduce coal inventory levels.

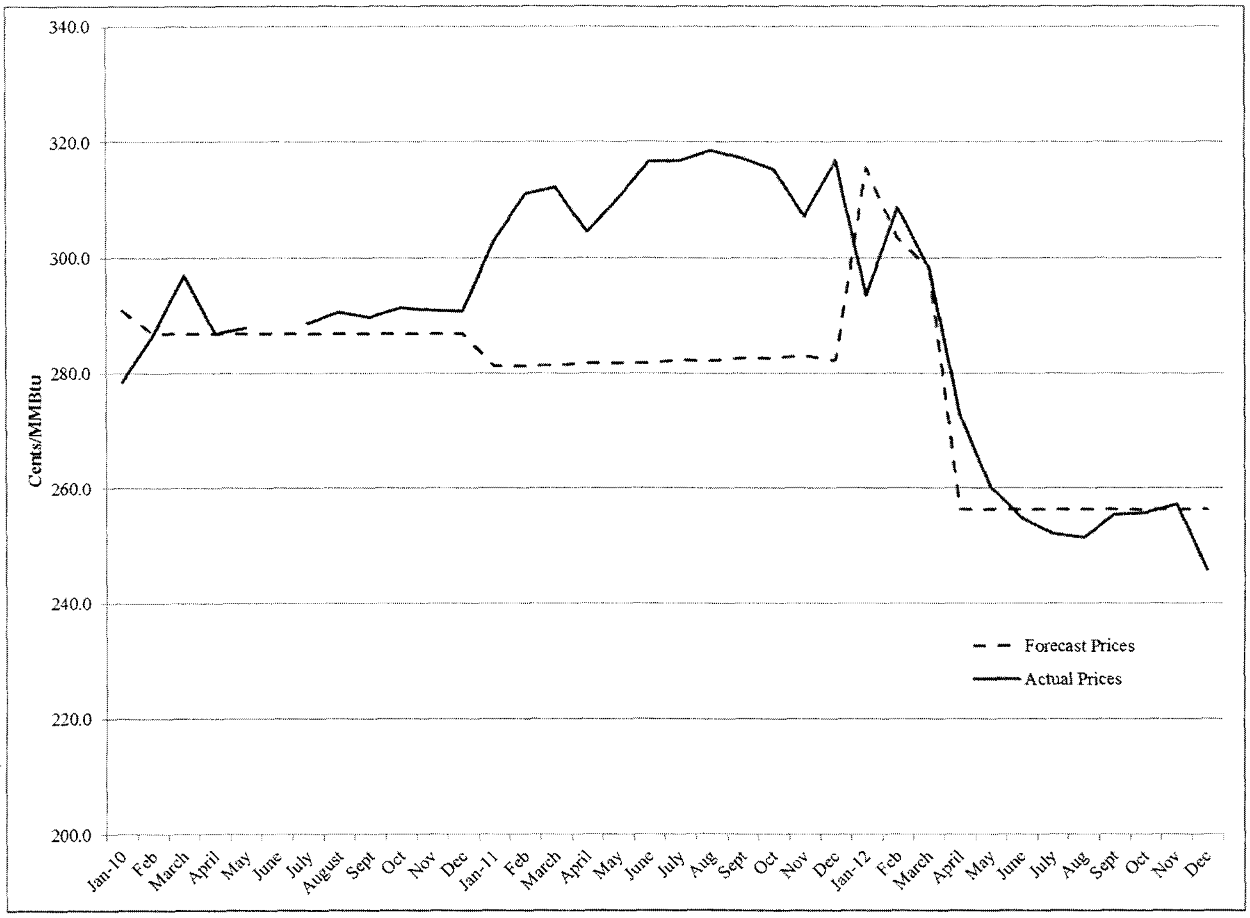
Geographic Distribution of Coal Supply

[redacted]

3. Coal Prices

The next graph shows delivered coal prices for coal consumed at the Apache generating station.

Actual vs. Forecast Delivered Coal Prices



AEPCO prepared in December 2009 a coal-price forecast for the years 2010 through 2013. AEPCO has updated the forecast annually (in either the 3rd or 4th quarter) as the Cooperative prepared its operating plan for the following year.

The following, obtained from Energy Information Administration ("EIA") data, compares the prices of coal delivered to the AEPCO Apache Station with prices at four other Arizona power generating stations. Direct comparisons are difficult because of the significant differences in distance from mine to power plant, type of coal (Colorado/Wyoming/New Mexico), and contract type (term/spot). Overall, AEPCO prices have been competitive, especially considering Tucson Electric Power's ("TEP") Sundt Station. This information also demonstrates that AEPCO has reduced coal prices over the near term.

Energy Information Administration Data
Prices - Delivered $/MMBtu

AEPCO - Apache	**Mine State**	**Distance Miles**	**Contract**	**2010**	**2011**	**2012**
El Segundo	NM	500	Contract	$2.90	$3.15	$2.75
Lee Ranch	NM	500	Contract	$2.90	$3.12	
Black Thunder	WY	1140	Spot			$2.42
Buckskin	WY	1140	Spot			$3.01
APS - Cholla						
El Segundo	NM	193	Contract		$1.82	$1.90
Lee Ranch	NM	193	Contract	$1.69	$1.80	$1.86
SRP - Coronado						
El Segundo	NM	189	Spot			$2.71
Spring Creek	MT	1264	Contract	$1.64	$1.74	$1.83
Black Thunder	WY	1000	Contract	$1.65	$1.71	$1.84
Antelope	WY	1000	Spot	$2.40	$2.41	$2.49
TEP - Sundt						
McKinley	NM	600	Contract	$4.66		
TwentyMile	CO	1370	Contract		$3.53	$3.62
TEP - Springerville						
El Segundo	NM	211	Contract	$1.49	$1.84	$2.04
Black Thunder	WY	1000	Spot	$1.85		$2.14
North Antelope	WY	1000	Contract	$2.07	$2.02	$2.10
Antelope	WY	1000	Contract	$2.20	$2.38	$2.46

Independently, Liberty obtained the following comparative data from its own sources of mine price data for the three power plants that obtained short-term coal in 2012 from the Peabody El Segundo Mine in New Mexico:

2012 Mine Price Data
Short Term Coal Contract Prices

Power Plant	**Mine Price $/Ton**
Apache	[redacted]
Coronado	[redacted]
Springerville	[redacted]

These data show that AEPCO succeeded in 2012 in obtaining short-term contract coal for delivery to Apache on a competitive basis.

4. Contract Purchases and Summaries

AEPCO purchased all of its supply in 2010 and 2011for the Apache Station under a single coal supply agreement with Peabody COALSALES. The coal came from the Lee Ranch and El Segundo coal mines in New Mexico, under an agreement entered into during the fall of 2008. This contract provided for delivery of 1,100,000 tons of coal in 2009 and 1,150,000 tons of coal in each of the years 2010 and 2011. The transportation for this coal came under common carrier pricing authority with the BNSF Railway. This coal has an average heat content of 9,200 Btu/lb and a sulfur content of 0.93 percent. Negotiations for renewal of this contract with Peabody continued for much of 2012, and concluded with a new four-year contract as summarized below.

Low 2012 prices for natural gas and purchased power, combined with high coal inventory levels, allowed AEPCO to delay entering into a new contract for long-term supply beyond 2012. AEPCO did, however, enter into a number of short-term coal supply agreements for delivery in 2012. The next paragraphs discuss these agreements.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

AEPCO applies a structured process to purchasing its coal supplies. The procurement process starts with development of an RFP that specifies the details of the required coal supply. The specified parameters include desired length of term, preferred source of supply, delivery point, pricing provisions, quality and quantity. For example, the procurements in early 2012 started with an RFP issued to the Cooperative's list of potential coal suppliers. These potential suppliers (covering coal from Wyoming, Colorado and New Mexico) comprised those suppliers that AEPCO believed were capable of providing the desired coal supply.

Multiple bids came from potential suppliers. AEPCO began a detailed analysis process that considered all alternatives of supply and various blends of coals to achieve optimum economics and performance at Apache. AEPCO believed that not all bids were sufficiently favorable. It therefore in February issued a notice to all potential coal suppliers of the opportunity to refresh their bids. AEPCO conducted all evaluations on the basis of final delivered cost to Apache in dollars per MMBtu.

AEPCO first identified the most optimum economic package of coal supply, and then reviewed the proposed procurement with the internal Coal Supply Group. The procurement approved by the Coal Supply Group went to the AEPCO Board of Directors for final approval. The potential procurement underwent detailed discussion and the Board formally approved the procurement. However, in the case of the spot procurements [redacted], these agreements were approved under the Chief Executive Officer's spot coal supply purchasing authority matrix.

Liberty examined all of AEPCO's coal procurement for 2012. In all cases, AEPCO sent RFPs to appropriate lists of potential suppliers, performed detailed analyses, followed appropriate procedures, obtained proper approvals, and fully justified the procurement.

5. Contract Actions

During the period from January 1, 2010 through 2012, there were no coal contract price redeterminations invoked by AEPCO or its coal suppliers. There were no coal-contract terminations for reasons other than normal contract date expirations. Currently, no open or unresolved coal contract issues exist.

During the period from January 1, 2010 through 2012 one Force Majeure event occurred. Peabody COALSALES provided notice to AEPCO of Force Majeure at the El Segundo Mine in New Mexico on May 7, 2010. The mine had experienced unforeseen equipment breakdowns beginning on March 26, 2010. This Force Majeure event extended to August 11, 2010. It affected the delivery of 141,000 tons of coal to AEPCO. The parties met a number of times to resolve the issue of the affected tonnage. As a result of these meetings, these tons of coal were canceled out of the coal supply agreement for the year 2010.

During the period from January 1, 2010 through 2012 there was one contract renegotiation. [redacted]

[redacted]

6. Transportation

Apache receives coal from sources on the Union Pacific Railroad and on the BNSF Railway. For the years 2004 through 2008, AEPCO's only contracted fuel transportation was with the Union Pacific Railroad. It provided for a minimum volume of 1,000,000 net tons of coal per year. Volumes of coal shipped via the BNSF Railway moved under common-carrier pricing authorities (tariffs). After 2008, AEPCO shipped coal solely under railroad tariffs, and has not had any open or uncontracted coal transportation.

Rates for rail transportation of coal have formed a matter of significant attention for AEPCO. In 2008, the Union Pacific Railroad issued a 2009 transportation rate proposal that would have resulted in potential, dramatic price increases for AEPCO. At the same time, AEPCO was considering a new coal-supply agreement to run for three years from 2009 through 2011. Primarily due to expected large increases in transportation costs, AEPCO's 2008 coal RFP process threatened to produce an increase in total coal and transportation costs for 2009 of 124 percent over 2008, or $63 million annually.

This dramatic potential increase in transportation costs influenced AEPCO fuel strategies in a number of ways. Briefly, the potential increase in 2009 transportation costs led to AEPCO's coal stockpiling strategy in 2008 and to the decision to shift coal supply sources from a Union Pacific-sourced, Wyoming/Colorado mix to a New Mexico supply delivered on the BNSF. The three-year coal contract with COALSALES for delivery in 2009 through 2011, for coal from the El Segundo and Lee Ranch Mines, reflects that shift.

The proposed, dramatic increase in transportation rates led AEPCO to file a rate-complaint case with the U.S. Surface Transportation Board ("STB"). Finally, as discussed earlier, in November 2011, AEPCO received a favorable decision from the STB.

The following information summarizes annual coal transportation contracts and tariffs for the years 2010 through 2012:

2010

- Transportation provider – BNSF Railway
- BNSF Common Carrier Pricing Authority 57966
- Actual tons shipped = 1,101,050 tons from Lee Ranch & El Segundo Mines in New Mexico under the Peabody COALSALES contract.

2011

- Transportation provider – BNSF Railway
- BNSF Common Carrier Pricing Authority 57966

- Actual tons shipped = 1,056,935 tons from Lee Ranch & El Segundo Mines in New Mexico under the Peabody COALSALES contract.

2012

Transportation providers – BNSF Railway & UP Railroad

For Buckskin Mine

- BNSF Common Carrier Pricing Authority 58280
- UP Railroad Common Carrier Pricing Authority 4221, Item 2300 (via Pueblo, CO interchange)
- Actual tons shipped = 26,619 tons from the Buckskin Mine in Wyoming from Northern PRB BNSF coal origins via BNSF Railway and UP Railroad common carrier pricing authorities.

For Lee Ranch & El Segundo Mines

- BNSF Common Carrier Pricing Authority 58279
- UP Railroad Common Carrier Pricing Authority 4221, Item 2300 (via Deming, NM interchange)
- Actual tons shipped = 390,280 from Lee Ranch & El Segundo Mines in NM via BNSF Railway and UP Railroad common carrier pricing authorities.

For Southern PRB & Colorado Coal Mines

- UP Railroad Contract UP-C-54841, with maximum 300,000 tons allowed in 2012
- In November, AEPCO received allowance from UP to ship an additional 28,000 tons under this contract in the month of December 2012
- Enserco coal contracts were for a total of 328,000 tons under two agreements
- Actual tons shipped through 12/14/2012 = 296,821 from Black Thunder Mine.

7. Coal Inventory

a. Targets

AEPCO has established a coal inventory policy. The Coal Supply Group reviews it annually, taking into consideration the industry average of coal inventory, coal market conditions, coal blending objectives, transportation pricing, financial considerations (such as carrying costs), and other strategic objectives. [redacted] During that period various power sales contracts were in place, coal prices were more competitive, and member demand for energy was higher. AEPCO has calculated that of the total coal inventory, approximately 20 days of coal, or 66,000 tons are not recoverable, unburnable tonnage.

For various financial, operational, environmental compliance and business strategic reasons, AEPCO has not maintained its coal inventory within the target range since the year 2008.

b. Recent Coal Inventory Growth

AEPCO decided to permit inventory to grow in 2008, in order to avoid what it deemed to be excessive increases in coal transportation rates on the Union Pacific Railroad beginning in 2009. The actual stockpiling began in July 2008, and continued into early 2010.

In our previous review, Liberty determined that the AEPCO strategy for increasing coal inventory was appropriate. AEPCO followed a reasonable plan in 2010 and 2011 to gradually bring the inventory down. However, [redacted] in February 2012, inventory increased again dramatically. The following tables show the AEPCO coal inventory on both a Days and Tonnage basis. Actual useable inventory is 20 days less than the numbers shown.

Coal Inventory Levels (Days)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2011	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Coal Inventory Levels (Tons)

Year	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
2010	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2011	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
2012	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

The following graph presents a summary of the coal inventory data from the previous two tables:

[redacted]

For comparison purposes, the above graph also includes annual average coal inventory numbers for all national G&T Cooperatives, taken from the publication of the National Rural Utilities Cooperative Finance Corporation. These data show that the national average in 2010 was 73 days, and in 2011 was 74 days. These national G&T data show that AEPCO has continually ranked much higher than the national G&T average.

The graph shows visually that AEPCO was relatively successful in reducing coal inventory levels until about March of 2012, when coal inventory spiked up again. Inventory came down significantly in early 2012 because no coal was being purchased. As discussed earlier, the decision had been made to delay entering into a long-term coal contract, and negotiations were underway for short-term coal to be purchased in 2012.

One of the reasons that coal inventory has not come down more significantly is that AEPCO has been holding [redacted]. AEPCO does not find it currently economical for additional procurement because of its high coal costs and high transportation costs. Accordingly, this coal has not been part of recent coal consumption planning. Coal purchases after March in 2012 were greater than Apache coal burn; therefore, coal inventory increased again to the degree that purchases have exceeded consumption.

Because of high coal inventory levels, Liberty is recommending a reduction in value for ratemaking purposes, as discussed in Dennis Kalbarczyk's Direct Testimony on Rate Base and Revenue Requirement, specifically pages 16 and 17.

c. Physical Coal Inventory Measurements

AEPCO has been conducting annual coal inventory surveys since 2005 to confirm coal inventory levels and to ensure correspondence between book and physical inventory amounts. AEPCO began biannual physical surveys in 2008, because of the significant amount of coal in inventory, as compared to previous levels. Physical inventory measurements have been conducted using aerial flyover techniques and density measurements obtained through bore-hole samples.

In 2010 and 2011, AEPCO made adjustments to coal inventory using a 0 percent tolerance level – that is adjustments were made if there was any variation between coal physical survey results and book value. AEPCO conducted a 2012 survey of U.S. electric utilities, and determined that the Cooperative would be more in line with others if adjustments were only made when variations between survey and book exceeded +/- 3 percent. Accordingly, the following adjustments were made to book inventory as a result of the semiannual physical coal surveys:

Coal Inventory Comparison – Physical vs. Book Inventory

Date	Book Inventory	Physical Inventory	Difference (tons)	Difference (percent)	Adjustment (tons)
8/2010	[redacted]	[redacted]	(10)	(0.002)	(10)
12/2010	[redacted]	[redacted]	5,873	1.38	5,873
12/2011	[redacted]	[redacted]	(15,942)	(4.46)	(15,942)
6/2012	[redacted]	[redacted]	2,472	0.57	-0-
12/2012	[redacted]	[redacted]	2,062	0.56	-0-

The table does not show that survey results in mid-2011 called for an adjustment of (16,447) tons. Management decided to wait until the December survey results before making any adjustment, since mid-year survey results were not received until the end of August 2011. The table also shows that in 2012 the survey results and book value were within +/- 3 percent; therefore, no adjustments to book value occurred.

C. Conclusions

1. AEPCO effectively procured short-term contract coal for delivery in 2012.

AEPCO was effective in 2012 in procuring short-term contract coal for delivery in 2012. Of the three power plants receiving short-term contract coal from Peabody's El Segundo Mine in New Mexico in 2012, AEPCO's Apache Station had the lowest mine price on a $/Ton basis.

2. AEPCO achieved favorable reductions in coal costs in 2012, on a $/MMBtu basis, through its short-term coal procurement strategy.

Comparative coal price data obtained by Liberty showed that AEPCO short-term coal contract prices in 2012 were the lowest of three Arizona power plants obtaining coal from the Peabody El Segundo Mine in New Mexico. These prices were as follows:

Power Plant	Mine Price $/Ton
Apache	[redacted]
Coronado	[redacted]
Springerville	[redacted]

For comparison, the following table shows how these prices contributed to an overall reduction in Apache coal prices for the years 2010 through 2012, on a $/MMBtu basis:

AEPCO - Apache	Mine State	Contract	2010	2011	2012
El Segundo	NM	Contract	$2.90	$3.15	$2.75
Lee Ranch	NM	Contract	$2.90	$3.12	
Black Thunder	WY	Spot			$2.42
Buckskin	WY	Spot			$3.01

3. AEPCO achieved favorable results through its challenge of rail rates, through filings with the Surface Transportation Board.

The Surface Transportation Board's ("STB") Decision represented a favorable result for AEPCO. The decision describes the procedure for calculating AEPCO's maximum reasonable rates as follows:

> *In this case, AEPCO has demonstrated that the challenged rates are unreasonable under the SAC test. Accordingly, we will order defendants to pay reparations to AEPCO (with interest) for prior shipments, and we will prescribe the maximum lawful rate that defendants can charge through 2018 . . . . . . We will order the railroads to establish transportation rates no higher than the 180% jurisdictional floor, which will provide AEPCO a 28% reduction in the transportation rate for 2009, and an average reduction of 37% over the 10-year period for which AEPCO is entitled to relief. . . . . Although the record does not provide the data needed to calculate precisely the total amount of reparations due to AEPCO, we estimate that reparations are roughly $4.5 million in 2009. We further estimate that the total relief AEPCO will obtain as a result of this order – including both reparations and the lower prescribed rate through 2018 – will approximate $63 million (in current dollars).*

In addition, the STB decision opened up new coal supply origins, increasing competition among suppliers. Significantly, both the BNSF and UP will now compete for AEPCO's business out of the Powder River Basin.

4. AEPCO's forecasting of coal consumption has deteriorated since 2010. The difference between actual and forecast was within a typical range in 2010 and 2011, but was well outside a normal band percent in 2012. *(Recommendation #1)*

AEPCO data showed a reasonable correlation between forecast and actual coal consumption for 2010, with the difference being only 0.4 percent. For 2011, the variation was in the same direction, with forecast being higher than actual, but with an 8 percent difference between forecast and actual. For the year of 2012, the difference was in the opposite direction, with actual consumption being 30.0 percent higher than forecast. This divergence was due mainly to natural gas prices, which were much lower than anticipated during 2011 and 2012.

5. **AEPCO did not do a good job in 2012 of matching short-term coal procurement with coal consumption.** *(Recommendation #2)*

Deliveries under the long-term contract had terminated for the year 2012, and the Company had the opportunity through its short-term coal purchases to purchase minimum quantities of coal. Such purchases should have been only as necessary for coal consumption to be matched by a combination of coal from inventory and coal from current purchases. Because of poor planning, coal inventory levels grew significantly from March 2012 through July 2012, instead of declining further as they had been since early 2010.

6. **AEPCO took a significant positive step in 2012 related to long-term coal inventory management.**

In 2012, AEPCO committed to positive action related to long-term coal inventory management. The Cooperative entered into a new long-term coal contract for deliveries [redacted] This action will permit more positive steps in managing coal inventory and bringing inventory levels down to more reasonable levels.

7. **AEPCO made a good decision in 2012 to modify the book inventory adjustment tolerance band to +/- 3 percent.**

In 2010 and 2011, the Cooperative had been making adjustments to coal book inventory levels based on a zero tolerance band between results of coal physical inventory survey results and book inventory levels. Beginning in 2012, the Cooperative modified the tolerance band to +/- 3 percent difference between physical inventory survey results and book inventory levels. This is in line with industry standards.

8. **AEPCO coal physical survey results, when compared to actual coal inventory book values, have been favorable from 2010 through 2012.**

The percentage difference variations at the survey adjustment times from 2010 through 2012 have been (0.002), 1.38, (4.46), 0.57, and 0.56. Negative differences indicate book values greater than physical survey values, and positive values indicate book values less than physical survey values.

9. AEPCO's policy on management of [redacted] in inventory has not been effective. *(Recommendations #2 and #3)*

[redacted] This is a premium coal with high Btu/lb, low sulfur, but also high cost. Consequently, the Cooperative not been considering this coal supply as normal consumable inventory, but has been holding this coal in inventory since 2008, and reserving its use for some undefined point in the future for possible operational and economic advantages. Such AEPCO policy on the [redacted] contributed to the difficulty in bringing coal inventory levels down to more reasonable levels.

D. Recommendations

1. **Re-evaluate forecasting of coal consumption to improve the match between forecasts and actual coal consumption.** *(Conclusion #4)*

The match between forecasts for coal consumption and actual coal consumption has steadily been deteriorating since 2010. AEPCO must re-evaluate its processes for forecasting coal consumption. This analysis is especially critical because consumption forecasts play a large role in coal procurement decisions, and consequently management of coal inventory levels. Reevaluation of forecasting processes will be supportive of the following recommendation to manage coal inventory levels more aggressively.

2. **Manage coal inventory more aggressively.** *(Conclusions #5 and #9)*

AEPCO coal inventory at Apache has remained considerably above its target levels since early 2008. Some progress has been made in lowering inventory levels, but the Cooperative must demonstrate more consistent actions on inventory management which integrate all segments of overall coal supply management with the goal of bringing coal inventory levels down into the target range.

3. **Reevaluate the management of the premium, high Btu coal that has been withheld from the generation mix in inventory.** *(Conclusion #9)*

The significant quantities of [redacted] in inventory at Apache present considerable advantages to the Cooperative in terms of economics, quality of fuel available for consumption, and inventory management. These factors must be reevaluated with the goal of integrating them in the optimum manner, considering current conditions of the marketplace, inventory levels, and fuel supply (both quality of fuel available as well as the match with coal versus natural gas decisions).

IV. Power Transactions

A. Background

The capacity from Apache is all allocated to its members in accordance with the levels specified in the Cooperative's 2001 restructuring agreement. AEPCO has relied predominantly on its own generation to supply members' loads, supplemented by small purchased power contracts and market power purchases. Its purchases fall into three principal categories:

- Contracts with the Western Area Power Administration ("WAPA") and two small peaking power contracts
- Short-term purchases from regional power markets, when AEPCO is able to buy on a real-time (hourly) basis at a delivered price lower than its marginal cost to generate or to take from its purchase contracts
- Shorter-term purchases of market power that may be acquired to replace AEPCO generation during maintenance outages or at peak load times.

AEPCO no longer makes substantial term sales of capacity and energy in excess of its member's needs. In the recent past, a 20-year, 100 MW wholesale sales contract with Salt River Project ("SRP") provided for a large sale of capacity and energy that provided an offset to purchase power costs charged to members. When the SRP contract expired on December 31, 2010, AEPCO assigned the capacity and energy from the contract to its members in accordance with the 2001 restructuring agreement and the members' contracts based on the proportion of their load to total member power requirements in 2001.

B. Findings

1. AEPCO Power Purchases

a. Power Purchase Summary

The table below shows AEPCO's power purchases from 2008 through 2012. Market energy comprises the primary purchase vehicle. AEPCO uses them when economic as compared to AEPCO's own generation or firm peaking contracts. Short-term purchases primarily employ an hourly approach, with purchases of two weeks or more to provide energy during a generating unit maintenance outages. [redacted] Natural gas pricing has driven electricity pricing.

The pricing of electric energy in the regional market is driven by natural gas prices, which have fallen drastically. However, AEPCO's MWh purchases also show a slight decrease from levels in 2008 and 2009, despite the much lower pricing. The partial-requirements members may buy directly from the markets. Lower market pricing encourages this activity to a greater degree, which displaces some of AEPCO's purchases.

Related transmission expenses have declined from [redacted] in 2008 to [redacted] in 2012, with a majority of the total annual transmission expenses paid to affiliate Southwest Transmission Cooperative.

[redacted]

2. Firm Purchase Contracts

AEPCO currently has contracts for firm power purchases from three sources: WAPA and two peaking contracts with Calpine-Southpoint and Dynegy-Griffith. The WAPA contracts provide a small amount of inexpensive, federal-project hydroelectric power allocated to AEPCO and its members. The WAPA contracts provide for about 32 MW of base load capacity and energy in the summer and about 20 MW during the winter months. However, AEPCO advises that WAPA has more recently been delivering only about 60 percent of the contracted levels, due to dry conditions in the western region. [redacted] The Cooperative therefore takes its maximum allocated amounts at all times.

In 2003, AEPCO solicited proposals for base load, medium-term, and peaking options, with the years 2008 through 2014 of primary interest. This solicitation and evaluation process resulted in AEPCO peaking contracts with Calpine-Southpoint and Dynegy-Griffith. They cover May to October in each year from 2008 through 2014. The Southpoint contract varies by year [redacted]

AEPCO has called upon the Southpoint contract during the peak season in each year from 2008-2012, but has not used the Griffith contract. These contracts comprise a small percentage of the Cooperative's total electric energy purchases. AEPCO advises that the capacity of the peaking contracts is allocated about 97 percent to partial requirements member Trico. AEPCO was arranging for incremental power supply resources for this formerly all-requirements member prior to the initiation of the contracts.

3. Electric Resource Planning

Resource planning for member system requirements has changed much in recent years, as AEPCO's largest ARMS have become PRM. Traditionally, all six of AEPCO's distribution cooperative members had all-requirements contracts. Mohave and Sulfur Springs, the largest and second-largest members, changed to partial-requirements contract status in 2001 and 2008, respectively. Trico, the third largest distribution member, became a partial-requirements member in 2011. AEPCO allocated to both PRMs and ARMs responsibility for a share of AEPCO's power supply resources as part of the Cooperative's 2001 restructuring. The allocations occurred in accordance with their June 2001 load requirements as a percentage of the AEPCO total. The three PRMs take responsibility for about 89 percent of AEPCO's capacity. The three ARMs take the remaining 11 percent. The PRMs have the option to arrange for their own capacity and energy requirements above the allocated levels. They have exercised this option. Each partial-requirements member has taken on their own planning functions to meet incremental resource needs. AEPCO now plans for only the electric resource needs of the ARMs. Mohave and Sulfur Springs each use its own consultant to help with resource planning. The PRMs do not rely on AEPCO to plan for their electric resource needs, but AEPCO says that it is talking with these members regarding joint peaking resources in the future. However, the fact that the PRMs have decided to do resource planning on their own in the recent past indicates a lack of confidence among the parties and a refocused relationship with AEPCO.

AEPCO has worked in recent years with the regional Southwest Public Power Resources Group (SPPR) electric joint purchasing group to solicit power supply resources. SPPR is an association of some 40 not-for-profit electricity providers and irrigation districts located in Arizona and southern Nevada. A 2010 SPPR solicitation included AEPCO, which participated for the future electric resource needs of the all-requirements members only. The participation in the SPPR solicitation resulted in a new, fully dispatchable [redacted] contract with Sempra for 2015 through 2039. The SPPR group in total signed contracts for 271 MW in June 2011. Trico participated in the solicitation for its own future requirements, but opted out of any purchases.

4. Trading

a. Trading Operations Transfer to ACES

ACES Power Marketing ("APM") has provided middle office (risk management) and back-office (billing and invoicing) services to AEPCO's power market operations for several years. [redacted]

[redacted]

The director of energy services and an energy services project administrator remain at AEPCO. The director serves as an interface and coordinator between APM and the Cooperative, and oversees the overall trading operations, billing services, and the relationship with APM. The project administrator performs analytical support, billing unit modeling, reporting and compliance work, and serves as an interface with the accounting apartment.

[redacted] AEPCO pays APM approximately [redacted] per year for its services. AEPCO also continues to have ongoing costs of about $1.5 million per year for retained staff, transmission systems support, programming staff and costs, and other support items related to trading operations not transferred to APM.

AEPCO performed an evaluation of moving the trading operations to APM in 2011, prior to the transaction. The evaluation compared AEPCO's existing budgets for the trading operations with APM fees to be paid and the ongoing costs of support services retained. Savings to AEPCO came from two sources: a) the staff reduction of two employees not replaced (about $250,000 per year); and b) estimated cost savings related to APM's sharing the cost of its new western region trading center [redacted] The evaluation notes that APM can guarantee the savings because it plans to move its trading operations for two other western customers to the new office in 2012 and pass along a portion of the resulting savings to AEPCO.

b. Term Trading and Scheduling

Another effect of the three largest AEPCO members being PRMs is that they may schedule their own energy requirements with AEPCO (above minimum take levels and up to their allocated limits). They may also schedule and purchase AEPCO power, and sell part or all of it in the marketplace, if they choose. These scheduling options for the partial-requirements members have a large impact on trading operations and their capabilities.

APM performs planning and scheduling on two-day ahead and day-ahead bases. Local traders contact the Mohave, Sulfur Springs, and Trico PRMs for their estimated schedule requirements, and perform a two-day ahead generation scheme. To the extent that the two-day ahead plan requires natural gas, the traders notify natural gas traders in Indianapolis. APM notes that little natural gas is purchased for the Apache gas-fired units, which do not run commonly, because of their comparatively low efficiency.

APM performs day-ahead scheduling for AEPCO the morning before the trading day. APM prepares a schedule of its upcoming resource commitments. This schedule seeks most economically to meet AEPCO's system requirements for the next day. Scheduling is performed for the three PRMs as well as the much smaller ARMs. APM notes that its day-ahead schedulers must recognize and be reactive to the option that PRMs have to change their individual schedule as little as 70 minutes before the dispatch hour. The traders note that this last-minute option for the PRMs "ties the hands" of the schedulers. The schedulers are naturally discouraged from locking down day-ahead trades and resources that may have to be unwound at the last minute due to a trading directive from a partial-requirements member.

We asked APM about term trading opportunities for AEPCO; *e.g.*, buying or selling power for more than two or three days. Traders will "look at" trades of one week to one year, but they have found that very little opportunity exists for such trades. "Almost zero" term trading occurs because the PRMS severely limit this ability with their potential to change trades and volumes at the last minute (70 minutes before the trading hour). The APM traders would have to second-guess the PRMs. They effectively have no control or ability to make term trades as a result. APM notes that its group has much more control over the types of trades for the ARMs. Those members, however, account for only a small fraction of the trading volume. The traders note that the PRMs would be able to make term trades for their own accounts, because those members control the eventual scheduling and dispatch for their own requirements. Term purchases occasionally occur during maintenance outages for the Apache coal units, such as a recent purchase for Mohave.

c. Real-time Trading

The results of the day-ahead schedule also go to APM's real-time desk, for management of economic dispatch on an hourly basis. An APM team of real-time traders enters into hourly transactions for purchases and sales, if they are economic compared with AEPCO's other power supply resources. The real-time desk continually monitors the system loads and the resources operating to meet the loads, and looks ahead to determine changes in load, resources and potential opportunities in the upcoming hours. An energy marketer assesses the dispatch order for each hour, and compares this order to the costs of market resources (from real-time market information) available for purchase with AEPCO's incremental generating costs. The APM energy marketer will make hourly purchases from the market when economically advantageous. The real-time traders "shop the market" to fill in requirements in upcoming hours.

The resource options for the real-time traders usually boil down to two alternatives: (a) dispatching the Apache coal-fired units or (b) buying market power. These two resource options lie "on the margin" at most times, except during peak load seasons. In January 2013, the cost of the Apache coal units plus a percentage pricing factor for other costs at the plant and for cycling costs peg the "bogey price" for APM to compare with the price of market purchases. Coincidentally, the dispatch costs and pricing for the Apache coal units is near the cost of market purchases. This phenomenon causes the Apache coal units to be dispatched a portion of the time, and for gas-fired market purchase trades to be made at other times. APM reports that, except for peak load periods, the purchase market for the region is set by natural gas-fired combined cycle generating units with heat rates of between 7,500 and 8,000 on the margin. The market prices increase toward a natural gas-fired heat rate of about 10,500 during peak periods. [redacted]

Both operating considerations and the dispatch directions of the PRMs constrain the range of dispatch discretion for the two Apache coal-fired units. The effective range of dispatch for the units lies between a minimum load of 55 MW and the plant capacities of 175 MW each. The minimum load of 55 MW sets the lowest level at which the units can operate, if they are running. The PRMs have a minimum must-take requirement of about 105 MW for each unit. The PRMs have the right to direct the dispatch of between 105 MW and 175 MW per unit, with 70 minutes lead time. If the member loads fall below 105 MW per unit, AEPCO/APM may ramp down the units from the 105 MW level to as low as the 55 MW minimum at their discretion. This resulting arrangement causes additional lack of flexibility for AEPCO/APM to control effective economic dispatch, again due to the PRMs' rights to control a portion of the dispatch range.

d. Risk Management

APM provides middle office risk management services to AEPCO. APM performs a "trading control" function for gas and power transactions and trading operations. APM's schedulers receive printouts from the Intercontinental Exchange ("ICE") system. The printouts include the transaction details. Transaction information is entered into APM's Allegro transaction tracking system by the end of each trader's work shift. The trade authority limits are programmed into the Allegro system, which provides notifications for trades not within authorized limits. The Allegro system maintains the transaction records, and serves as the primary tool and data repository for risk management.

A local APM employee responsible for AEPCO transactions performs the middle office risk management functions. This risk manager validates all on the day after or two days after the actual trade date. The risk manager uses tools such as "web sweep" and "web scheduler" and automated transaction queries to validate the trades. The authority matrix undergoes review to ensure compliance with all limits. The Allegro system will already have flagged trades not meeting limits. The risk manager follows the trading practices adopted by APM. The practices are essentially identical to the AEPCO practices set out in the "Electric Power and Transmission Trading Practices" dated March, 2010 and in force when APM assumed the trading functions. A twice-daily trade data report provides trading information on both a month-to-date basis and for the previous month. The trade data reports are a key output of the risk management function that also includes credit exposure reports. The AEPCO energy services project administrator enters transaction information from this report into the ITS software and verifies for the company.

APM also provides from its home office in Indianapolis back-office billing, invoicing, and settlement services for AEPCO transactions. Settlements occur at each month-end and undergo verification with the counterparties. Verifications include date, hour, volumes, prices and dollar amounts. Following settlement activities, APM provides AEPCO with monthly transaction reports.

C. Conclusions

1. AEPCO's transfer of its trading operations to ACES Power Marketing has resulted in similar results at a somewhat lower cost.

AEPCO turned over all front office scheduling and trading functions to APM in May 2011. APM now performs these services on a contractual basis. AEPCO transferred nine trading staff employees to APM and purchases the trading operations services for fees. Liberty's follow-up review of AEPCO/APM scheduling, real-time dispatch, and trading functions indicate that they are reasonably managed, albeit within limitations on their scope that are discussed in Conclusion #3. AEPCO/APM has effectively scheduled and dispatched its own plants and long-term contracts, while taking advantage of hourly market opportunities to buy economic purchased power. AEPCO's market electric energy purchases averaged [redacted] in 2012, as it realized lower energy pricing driven by natural gas prices decreases.

A review of AEPCO's analysis of the trading operations transfer indicated that the savings to AEPCO were to come from two sources: a staff reduction of two employees that were not replaced, [redacted] Liberty believes that the savings through the reduction of two employees could have occurred while keeping the functions in-house. Attributing them, therefore, to the APM arrangement is overly generous. Nevertheless, AEPCO should realize the APM-guaranteed cost savings that are a function of the APM transition.

2. APM also provides effective trading operations risk management and back-office settlement functions to AEPCO.

APM continued to provide middle office risk management and back-office settlement services to AEPCO, as it has for several years. The middle office risk management functions are performed by a local APM employee that is responsible for AEPCO transactions and includes transaction verification and compliance, with similar trading limitation safeguards to those that were previously in place at AEPCO in 2010. APM also provides back-office billing, invoicing and settlement services for AEPCO through the APM home office in Indianapolis. Liberty believes that these trading services remain effective and are reasonably independent within APM's organization structure.

3. The effectiveness of trading operations and resource planning are limited by the contractual rights and actions of AEPCO's partial-requirements members.

The PRMs' relationships with AEPCO are dysfunctional. The trading operations and resource planning are two components of AEPCO's operations that suffer as a result.

AEPCO's electric resource planning is currently limited to the needs of its three ARMs, who comprise only about 11 percent of its total. The PRMs have the contractual option to arrange for their own capacity and energy requirements above the levels assigned to them in AEPCO's 2001 restructuring, and have exercised this option. For incremental resource needs, the PRMs have each taken on their own resource planning activities. The fact that the PRMs have decided to do their own resource planning removes from AEPCO most of the responsibility for one of their primary functions; *i.e.*, planning for the incremental electric resource requirements of its members. The recent SPPR joint resource solicitation resulted in only a [redacted] contract for the future needs of the all-requirements customers, signifying AEPCO's limited current role in resource planning.

The three PRMs are also entitled to schedule their own energy requirements with AEPCO above minimum take levels. They have exercised this option to the detriment of trading operations effectiveness. Very limited term trading occurs because trades made by the APM traders could later conflict with the wishes of PRMs, who have the right to change scheduled dispatch and trading volumes as little as 70 minutes before the trading hour. The trading operations effectively have no control or ability to make term trades as a result.

Day-ahead scheduling and real-time trading are also negatively affected by this situation. The day-ahead schedulers must recognize and be reactive to the option of the PRMs to change their individual schedule as little as 70 minutes before the dispatch hour. This option effectively "ties the hands" of the schedulers, in that they are discouraged from locking down day-ahead trades and resources that may have to be unwound at the last minute. It also causes AEPCO/APM real-time traders to have reduced control over economic dispatch due to the PRMs' rights to control a portion of the dispatch range of the Apache coal units.

D. Recommendations

Liberty does not have recommendations regarding partial-requirements members' effect on resource planning and trading operations, as their options to plan for their resource needs and schedule trading and dispatch operations are contractually guaranteed.

V. PPFAC Mechanism Review

A. Background

AEPCO has had a PPFAC since 2005, following ACC Decision No. 68071. Modifications to the PPFAC were approved in the Commission's ruling (see Decision No. 72005) in AEPCO's prior rate case filing. AEPCO's current rate case filing requests continuation of the PPFAC with two modifications.

Liberty reviewed the continuing need for the PPFAC, AEPCO's two requested modifications, and the processes by which the Cooperative computes the power cost adjustor calculation. Liberty's review incorporated the results of our work described in the Fuel Oils and Natural Gas, Coal, and Power Transactions sections of this report, as well as the Engineering and Power Plant Operations review provided under separate cover. Liberty addressed the PPFAC and proposed modifications by undertaking the following activities:

1. Analyzing the costs and revenues subject to the PPFAC.
2. Assuring whether the areas covered, *i.e.;* cost elements, conform to PPFAC provisions.
3. Verifying the over/under recovery PPFAC costs value and rate calculations.
4. Proposing any mitigation measures that are appropriate.
5. Identifying means for calculating and reporting revenues to monitor changes, if necessary.

1. PPFAC Introduction

Decision No. 68071 authorized a PPFAC consisting of the following major components:

1. Establishment of power cost adjustor bases for all- and partial-requirements members.
2. Monthly calculations of all-requirements and partial-requirements Class A members' fuel and purchased power costs over-collection and/or under collections.
3. Establishment of bank balancing accounts for each Class A Member subject to the PPFAC.
4. Development and filing of semi-annual all-requirements and partial requirements Power Cost Adjustor Rates.

In the prior rate case, Decision No. 72055 approved modifications to the Class A Members' rate schedules and the PPFAC. The changes separated the PPFAC into Base Resources and Other Resources categories for the Class A Members. The separation of PPFAC charges into these categories further required that development of the applicable charges and over/under collections be calculated upon the same basis. On October 20, 2011, AEPCO filed an application requesting that the Commission amend its Decision No. 72055 because AEPCO's tariff design erroneously assigned approximately $3.8 million of fixed gas costs related to flame stabilization as "reservation" rather than "capacity" charges. Reservation items therefore were improperly allocated to the Base Resources and Other Resources energy rates, rather than to "Fixed Monthly Charges" related to capacity. Commission Decision No. 72735 approved the amendment as requested. The error resulted in a benefit to Mohave and SSVEC at the expense of Trico. AEPCO requested a shift and recalculation of the rates, which was approved. Finally, in order to mitigate the rate impacts on its members and their retail customers, unanimous consent of the Class A Members was agreed to and approved by the Commission which provided for a write off of the approximately $1.998 million in fixed gas costs which it incurred from January 1, 2011 to July 1, 2011.

2. Current PPFAC Calculations

Separate fuel and purchased power cost adjustor bases for Base Resources and for Other Resources for the collective Class A ARMs and for each Class PRMs were set according to the tariff provisions, and adjusted accordingly based upon the amended decision. The PPFAC adjustor rate was initially set at zero until new adjustors are stable as provided for in the tariff in accordance with the approved Plan of Administration ("POA").

The results of the PPFAC calculations will be applied to the rates of collective ARMs and PRMs through the power cost adjustor rate commencing on September 1, 2011 to be effective October 1, 2011 and thereafter. On or before March 1 or September 1, AEPCO will file: (1) calculations supporting revised adjustor rates and (2) new tariff schedules reflecting the revised rates with an effective date of April 1 or October 1, respectively.

Finally, each month, AEPCO will continue to submit a report of its calculation of the collective ARMs and PRMs Base Resources and Other Resources fuel and purchased power costs over-collection and/or under-collection to the Utilities Division, Compliance Section of the Commission. In addition, AEPCO continues to provide confidential information regarding generating units, power purchases and fuel purchases on a monthly basis.

B. Findings

1. 2011 PPFAC Review

Liberty verified that the rates approved were consistent with the rates imposed to include the continued use of the appropriate authorized rates when calculating the fuel adjustors and bank balancing reporting. Liberty also reviewed a sample of the monthly collective ARM and PRM over-collection and/or under-collection reports submitted to the Utilities Division, Compliance Section. These reports are also subject to review by AEPCO's internal audit staff.

Liberty tested the accuracy of the calculations, including a detailed review of one of the filings to verify internal report formula calculations. Liberty also reviewed source documents and related policy and procedures pertaining to fuel purchase orders for all fuels and reconciliation to fuel requirements and contracts. The review also addressed how invoices and cash vouchers were processed and reconciled, including prices, quantities, and BTUs. Matters related to transportation charges and contract changes were also reviewed in detail. Liberty also conducted a review of AEPCO's general ledger accounts related to the cost of fuel and purchased power components included in the PPFAC. The Liberty review includes the work described in sections II through IV of this report. We also relied on the engineering analysis of the Apache station as it relates to plant performance and reliability and overall fuel cost components.

2. Cost Included in the PPFAC

The costs that have been included in the PPFAC since inception include the cost of fuel and natural gas consumed in AEPCO generating stations, as recorded in RUS Accounts 501 and 547. The descriptions of these accounts follow:

501 Fuel.

A. *This account shall include the cost of fuel used in the production of steam for the generation of electricity, including expenses in unloading, fuel from the shipping media and handling, thereof up to the point where the fuel enters the first boiler plant bunker, hopper, bucket, tank, or holder of the boiler-house structure. Records shall be maintained to show the quality, B.T.U. content and cost of each type of fuel used.*

B. *The cost of fuel shall be charged initially to Account 151, Fuel Stock and cleared to this account on the basis of the fuel used. Fuel handling expenses may be charged to this account as incurred or charged initially to Account 152, Fuel Stock Expenses Undistributed. In the latter event, they shall be cleared to this account on the basis of the fuel used. Respective amounts of fuel stock and fuel stock expenses shall be readily available.*

547 Fuel.

This account shall include the cost delivered at the station (See Account 151, Fuel Stock) of all fuel, such as gas, oil, kerosene, and gasoline used in other power generation.

A different RUS Account (158) addresses the costs of SO2 allowances. Therefore, AEPCO's PPFAC, in contrast to many others, recovers no costs associated with the purchase or sale of SO2 allowances. AEPCO has generated sufficient numbers of these allowances to avoid any need for additional purchases. AEPCO has made a moderate number of sales in the past. It has in recent years been banking them, however, given a desire to assure a reserve sufficient to support operations and low market prices for allowances. RUS considers these allowances to be security for its loans; therefore, RUS requires that the proceeds of sales of allowances be applied to loan balances.

AEPCO's PPFAC also includes the costs recorded in RUS Account 555 (Purchased Power). The description of this account follows:

555 Purchased Power.

This account shall include the cost at point of receipt by the utility of electricity purchased for resale. It shall also include, net settlements for exchange of electricity or power, such as economy energy, off-peak energy for on-peak energy, and spinning reserve capacity. In addition, the account shall include the net settlements for transactions under pooling or interconnection agreements wherein there is a balance of *debits and credits for energy, or capacity. Distinct purchases and sales shall not be recorded as exchanges and net amounts only recorded merely because debit and credit amounts are combined in the voucher settlement.*

The AEPCO PPFAC describes purchased power as including energy purchased on an economic dispatch basis, purchases made as a result of schedule outages, and "all such" kinds of purchases made to substitute for AEPCO's own, higher cost energy. Another tariff clause includes purchases other than these, if recorded in RUS Account 555.

Account 565 covers wheeling costs, both firm and non-firm, except for network service transmission payments made by AEPCO to SWTC. Account 447 provides for revenue credits as it relates to Non-Class A sales for resale revenues, less revenues for fuel-related legal expenses. Liberty notes that legal fees are also to be excluded from accounts 501 and 547.

3. Proposed Modification to PPFAC in Current Rate Proceeding

AEPCO seeks approval of the continuation of its adjustor mechanism, with two modifications to how the PPFAC is calculated. The requested changes do not affect the cost included in the PPFAC, but would make changes related to rate design within the mechanism. AEPCO has stated that the request results from member input. The two requested modifications would:

- Recover **fixed fuel costs** from a separate PPFAC "pool" with its own fuel adjustor rate based upon a monthly charge
- Separate Bank Balances (over-collections and/or under-collections) from the fuel adjustor rate(s) and, instead, recover or refund said balance also as a separate rate through a six-month amortization temporary tariff rider.

AEPCO's rationale for recovering fixed fuel costs under its own monthly rate charge and a separate bank balance amortization tariff rider is that it would establish a more accurate reflection of cost to members based upon their corresponding cost causative factors. This approach would provide to members a more accurate and timely price signal regarding current AEPCO resource costs.

The current PPFAC adjustor rate includes two components, which comprise fixed fuel cost and the historic over/under collection amount. AEPCO bills them under the PPFAC at a single rate. This approach establishes an imprecise rate, when one compares the AEPCO PPFAC charge (both fuel energy and over/under collections) to the real time market rate(s). The three largest members are PRMs. Those not required to purchase energy from AEPCO can and do purchase resources from others.

AEPCO submits that the change will encourage the best use of resources. If fixed fuel costs are then separated, the remaining bank balance or over/under collection values would be reconciled via a six-month amortization tariff rider.

AEPCO further request that the Commission approve continuation of the efficacy provision as approved in prior rate cases. AEPCO can file a request with the Commission to review the efficacy of the PPFAC with the submission of any semi-annual PPFAC report. AEPCO believes this has supported its ability to administer the adjustor mechanism, and, if necessary, adjust previous PPFAC clause procedures with Commission approval.

AEPCO, further requests permission as part of closing the **current** clause procedures that any refund or collection of outstanding Class A Members' bank balances be based upon a 12-month amortization period. AEPCO finally requests that any carbon taxes, CO2 Cap and Trade Allowances, or similar levies, if any, mandated in the future be allowed to be recovered through the PPFAC.

Liberty reviewed the request, and discussed it with AEPCO staff. We find appropriate the request to separate the fixed fuel costs and bank balance components as requested. That change conforms to acceptable cost of service principles. The request would provide better cost comparisons, because it would be based upon a standalone fixed fuel cost component that members can compare in the market. The request also has the support of the members. The separate bank balance tariff or rider continues to assure that members will be treated equitably.

Liberty also finds acceptable the continuation of the efficacy process, which provides for the ability of all stakeholders to address matters of importance to the PPFAC, on both historical and going forward bases.

Liberty does not consider the request that future carbon taxes, CO2 Cap and Trade Allowances or similar levies be allowed to be recovered through the PPFAC. Such a blanket approval would not provide reasonable input by stakeholders, based on the specifics of future situations. It is important that all stakeholders be allowed a sufficient level of input to test the reasonableness of necessary changes and/or new cost to be included in the PPFAC. An ample review should be conducted to determine what efforts are taken to minimize cost components to be included, determine what if any cost are already reflected in existing rates, and then determine what cost, if any, above those already provided for in the current request should be allowed in the PPFAC.

However, the Commission's Decision No. 73183 (May 24, 2012) held open the Arizona Public Service Company ("APS") rate case docket for the purpose of allowing APS to later request a modification to its Plan of Administration to allow recovery of the cost of carbon dioxide ("CO_2") allowances. APS did file such a request that the Commission approved in Decision No. 73650 (February 6, 2013).

If the Commission is interested in similar treatment for AEPCO, the current rate case docket could be left open to accommodate a request by AEPCO that is less broad than the proposal included in the rate case application.

C. Conclusions

1. AEPCO's Cost and Revenues subject to PPFAC recovery are sufficiently documented, and current policy and procedures are followed.

Liberty conducted a review of AEPCO's policy and procedures in this area. Liberty's review did not find any material weaknesses with regard to the policies and procedures and how they are implemented and followed.

2. AEPCO's Cost Elements included in the PPFAC provision conform with Commission Allowances.

Liberty conducted a review and test of the cost permitted in the PPFAC. This included a review of the calculation of the PPFAC and the prescribed accounts which are considered as allowable cost within the adjustor. Liberty's review also included an examination of the general ledger accounts and verified that the calculations included, or excluded, appropriate items. For example, legal costs not permitted in actual fuel costs were appropriately removed from the general ledger accounts for coal and gas, when calculations of allowed cost were performed. Liberty found the values claimed to be reasonable, documented, and sufficiently satisfactory for audit and test purposes.

3. AEPCO's over/under Recovery PPFAC costs value and corresponding rate calculations are accurate.

Liberty conducted a review and test of the over/under recovery collection bank values for reporting and tracking purposes under the PPFAC. This included a review of the calculation of same and the classification of such values on member basis as well as on base resources and other resources group classification. Liberty also verified that the Commission approval to write off all of the approximately $1.998 million in fixed gas costs which it incurred from January 1, 2011 to July 1, 2011 due to the amended change at Decision 72735 discussed earlier was, in fact, excluded. Liberty found all of the related cost to be excluded as agreed upon. Liberty also reviewed and tested sample over/under rate calculations and found them to be reasonably accurate.

4. AEPCO's requested PPFAC modification to separate fixed fuel cost and bank balances with correspondingly separate rates reflects reasonable cost of service principles.

The request as proposed provides better cost comparisons based upon a stand-alone fixed fuel cost component to compare same in the market. The request also has the support of the members. The separate bank balance tariff or rider with a six-month amortization period continues to assure that members will be treated equitably. Liberty also finds appropriate the recommended close of the current PPFAC process by allowing for a 12-month amortization of current bank balances.

5. AEPCO's requested continuance of the efficacy process is reasonable and appropriate.

Liberty agrees with continuing the efficacy process, because it provides for the ability of all stakeholders to address matters of importance to the PPFAC, on both historical and going forward bases.

6. AEPCO's request that any carbon taxes, CO2 Cap and Trade Allowances or similar levies, if any, mandated in the future be allowed to be recovered through the PPFAC could circumvent reasonable stakeholder review and input.

Liberty understands that the request as proposed may provide for expedience, but such a blanket request is not appropriate. If the Commission prefers, the current rate case docket could remain open to accommodate a request by AEPCO that is less broad than the proposal included in the rate case application.

D. Recommendations

Liberty does not have recommendations regarding the historical PPFAC calculations as it currently exists.

Liberty may in part address the matter related to proposed changes to the PPFAC in its rate design testimony. However, we do recommend approval of the requested modification for a separate fixed fuel cost component rate and separate tariff rider rate to amortize bank balances over a six-month period. Assuming the Commission accepts the recommendation, AEPCO should also be directed to make the necessary changes to the Plan of Administration and related tariff pages.

Liberty recommends the continuation of the efficacy process.

Liberty recommends that the Commission reject AEPCO's blanket request that any carbon taxes, CO2 Cap and Trade Allowances or similar levies, if any, mandated in the future be allowed to be recovered through the PPFAC. If the Commission prefers, the current rate case docket could remain open to accommodate a request by AEPCO that is less broad than the proposal included in the rate case application.